Gasification and Liquefaction Alternatives to Incineration in Japan

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Article Outline

Glossary

Gasification Thermal process that involves the reaction of carbonaceous feedstocks with oxygen-containing reagents, usually air, oxygen, steam, or carbon dioxide, generally at temperatures in excess of 800°C

MSW Municipal solid waste

PET Polyethylene terephthalate

PVC Polyvinylchloride

Pyrolysis Thermal process that implies the degradation of the organic materials at temperatures in the range of 400–800°C and in the absence of oxygen or other reagents

RDF Refuse derived fuel

Slag Molten ash

SR Shedder residue

Definition of the Subject and Its Importance

The major technologies used in Japan for energy recovery from municipal solid waste (MSW) are mass burning incinerators combined with landfilling of ash. However, shortage of landfill space along with new regulations for dioxin emission control and the Japanese Containers and Packaging Recycling Law has stimulated active R&D and commercialization of relatively novel thermal treatment processes based on gasification and liquefaction of MSW.

The purpose of this article is to introduce novel gasification and liquefaction processes for MSW that are already commercialized in Japan and are potential future alternatives to mass burning for effective resource recovery from MSW.

Introduction

In Japan, about 40 million tons of municipal solid wastes (MSW) are incinerated each year. Of these, about 20 million tons are used for power generation and in total about 1,000 MW of electric power is produced from MSW. Most of these waste-to-energy (WTE) plants are large-scale plants exceeding 200 t/day scale.

The major technologies used in WTE plants in Japan are stoker-type mass burning of as received MSW, where the final residues such as ash are landfilled. However, shortage of landfill space and also new regulations for detoxifying the fly ash by-product of incineration, as of 2004, has driven many municipalities to accept relatively novel processes such as direct gasification and smelting and, also, rotary kiln or fluidized bed gasification combined with melting of the ash to a vitrified slag.

On the other hand, many municipalities have started to source-separate and collect the plastic materials contained in MSW, under the Japanese Containers and Packaging Recycling Law enacted in 1995. The segregated plastic materials are recycled by three methods: material recycling, chemical recycling, and production of solid fuel. One of the technologies in the chemical recycling technology is liquefaction of plastic wastes.

There are about 30 Japanese companies engaged in the development of gasification and ash-melting systems, which can be divided into three main types: (1) the vertical shaft types that melt the entire amount of wastes directly, (2) the fluidized bed types that gasify the wastes directly with slagging, and (3) the kiln types that gasify the wastes indirectly with slagging.

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This article introduces three novel MSW thermal treatment processes developed and commercialized in Japan: (1) The EBARA Fluidized Bed Gasification and Ash-melting Process, (2) The JFE High Temperature Gasifying and Direct Melting Process, and (3) the TOSHIBA Waste Plastics Liquefaction Process. These processes have the potential to be future alternatives to the existing mass burning processes for maximizing the effective recycling and utilization of MSW.

EBARA Fluidized Bed Gasification and Ash-Melting Process

Process Description

Since the year 2000, EBARA's Fluidized Bed Gasification and Ash-melting process (TwinRec process) is in operation in large commercial installations [1]. It is based on fluidized bed gasification in combination with ash melting. The following description is focused on the core components of the TwinRec system: the fluidized bed gasifier and the cyclonic ash-melting chamber.

Any type of waste can be fed into the gasifier. Only bulky wastes need to be cut to pieces smaller than 30 cm in length. The gasifier is a proprietary internally circulating fluidized bed of compact dimensions, operated at temperatures between 500°C and 600°C. The resulting syngas (fuel gas) and fine particles are entrained into the gas flow leaving the gasifier. The low gasification temperature in the fluidized bed leads to easily controllable process conditions.

The main function of the gasifier is to separate the combustible gases and the dust from the inert and metallic particles of the waste. Metals contained in the waste, such as aluminum, copper, and iron, can be recycled as valuable products from the bottom off-stream of the gasifier as they are neither oxidized nor sintered with other ash components. Together with these metals, larger inert particles are removed from the furnace. Smaller inert particles are returned to the gasifier where they serve as bed material. The fine inerts are blown out of the gasifier and enter the next stage of the process.

Figures 1 and 2 show the operating principle of the gasifier and the ash-melting furnace and the process flowsheet, respectively. The fuel gas and carbonaceous particles that are produced in the gasifier are combusted in the cyclonic ash-melting chamber at temperatures between 1,350°C and 1,400°C by the addition of secondary air. Here, the fine particles are collected on the walls, where they are vitrified and slowly flow downward through the furnace.

The molten slag collected in the furnace is then quenched into a water bath to form a granulate with excellent leaching resistance; this vitrified material meets all regulations for recycling in construction.

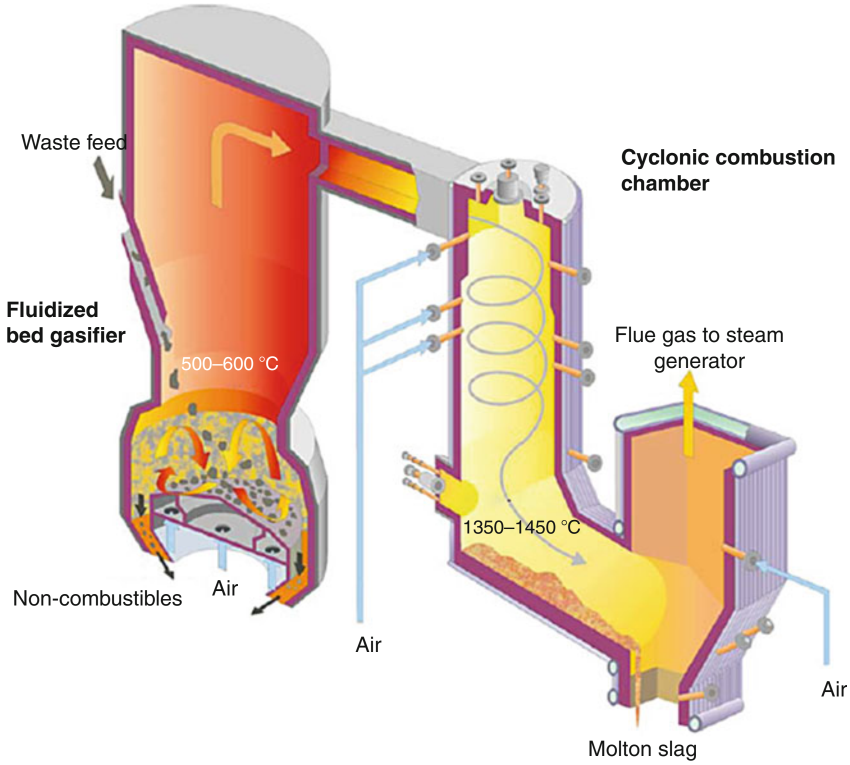
The high combustion temperature ensures that the most stringent dioxin emission regulations, below 0.1 ng TEQ/Nm^3 are met by means of minimal air pollution control measures.

The gasifier and the ash-melting furnace operate at atmospheric conditions, without any auxiliary fuels, except for start-up of the process or industrial oxygen. Due to the low excess air ratio that is required for complete combustion, the steam generator, boiler and air pollution control system are very compact. The energy content of the waste is converted into electricity and/or district heat with a high net efficiency.

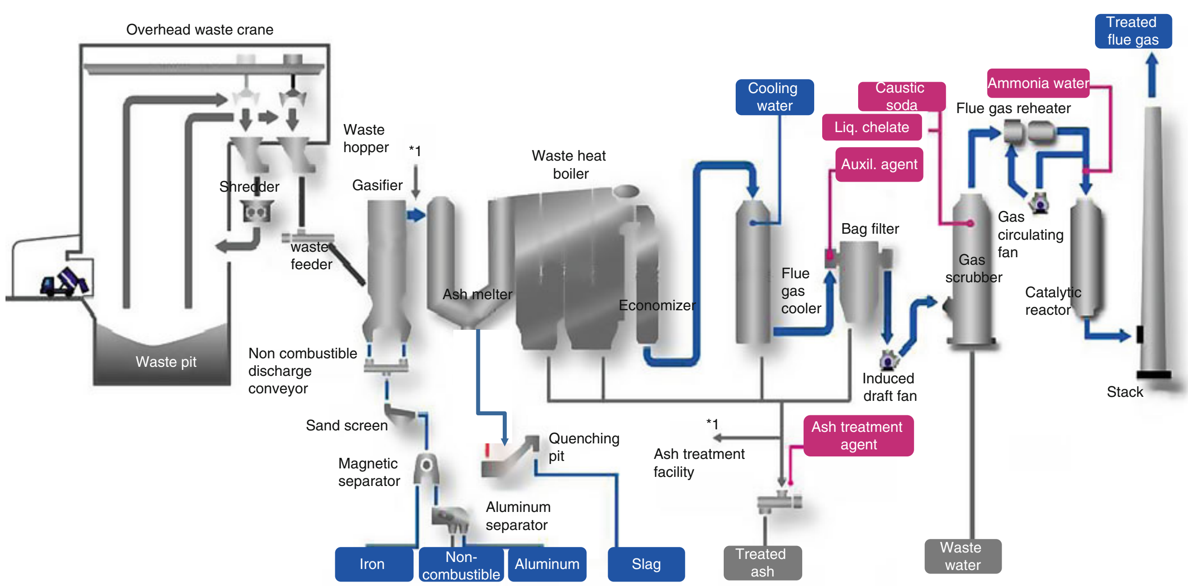
Recycling and Recovery

The Ebara TwinRec process can treat a wide range of materials generate product streams that match their characteristics and enable optimal resource recovery:

- Metals and alloys are not oxidized in the gasifier and can be recycled.
- Inert mineral materials are free of dust and organic matter and are also suitable for recycling.
- Mineral dust and metal oxide powder are vitrified into slag and can be used as construction materials.
- Any toxic organic substances are completely destroyed and the total organic content is transformed into energy.
- Volatile metal salts are concentrated into the secondary fly ash and can be used for zinc, lead, and copper recycling in the zinc industry.
- The amount of final residues for landfilling is reduced to very low values.



Gasification and Liquefaction Alternatives to Incineration in Japan. Figure 1
The fluidized bed gasifier and the ash melting furnace of EBARA TwinRec process



Gasification and Liquefaction Alternatives to Incineration in Japan. Figure 2
Flowsheet of the EBARA TwinRec process

The energy efficiency of TwinRec is better than the thermal waste treatment processes that require oxygen and therefore internal consumption of electricity. Also, the ash-melting furnace is integrated into the water-steam cycle, making use of the highest temperature level for steam production.

The slag granulate is the largest fraction for recycling. For successful application in the construction industry, it must satisfy technical criteria and pass the respective environmental certification. Technically, the granulate qualifies for various applications, replacing cullet, gravel, or sand. It can be applied as loose bulk material or as filler in combination with inorganic or organic binders. In Japan, the granulate is also used as a filler in asphalt.

Commercial Operational Experience

The first TwinRec commercial plant for MSW was built for Sakata Clean Union. The Sakata plant has a capacity of 2 x 98 t of MSW per day. Since the start-up of the first plant, several other TwinRec plants have been started, resulting in 15 plants in operation to date. Twelve of these plants treat MSW and are listed in Table 1.

Figure 3 shows a photograph of the largest plant at Kawaguchi that treats 420 t of MSW per day in three process lines generating 12 MW. In addition to vitrification of its own ashes, bottom and fly ash of another grate-type incinerator is also vitrified in the ash-melting furnace. Additionally, some of the secondary fly ash is recirculated and even the inert gasifier

Gasification and Liquefaction Alternatives to Incineration in Japan. Table 1 List of operational TwinRec plants

No.	Customer	Location	Capacity	Type	Inst. year	Electricity kw	
Municipal waste							
1	Joetsu Union	Niigata	15.7 t/24 h	TIFG	Mar.2000	45	Night soil sludge
2	Sakata Clean Union	Yamagata	196 t/24 h	TIFG	Mar.2002	1,990	
3	Kawaguchi City	Saitama	420 t/24 h	TIFG	Nov.2002	12,000	
4	Ube City	Yamaguchi	198 t/24 h	TIFG	Nov.2002	4,100	
5	Chuno Union	Gifu	168 t/24 h	TIFG	Mar.2003	1,980	
6	Minami-Shinshu Union	Nagano	93 t/24 h	TIFG	Mar.2003	800	
7	Nagareyama City	Chiba	207 t/24 h	TIFG	Feb.2004	3,000	
8	Chubu Clean Union	Shiga	180 t/24 h	TIFG	Mar.2007	3,000	
9	Dalsung	Korea	70 t/24 h	TIFG	Jun.2008	–	(HEEC license)
10	Eunpyeong	Korea	48 t/24 h	TIFG	Sep.2009	–	(HEEC license)
11	Hwasung	Korea	300 t/24 h	TIFG	Mar.2010	4,400	(HEEC license)
12	Kurahama Clean Union	Okinawa	309 t/24 h	TIFG	Mar.2010	6,000	
Industrial waste							
1	RER aomori renewable energy recycling Co., Ltd.	Aomori	450 t/24 h	TIFG	Nov–02	17,800	Shredder dust, sludge
2	Nikko Mikkaichi recycling Co. Ltd.	Toyama	63 t/24 h	TIFG	Jun–01	–	Shredder dust, waste plastic
3	Tokyo waterfront recycle power Co., Ltd.	Tokyo	550 t/24 h	TIFG	Aug–06	23,000	Industrial waste

Gasification and Liquefaction Alternatives to Incineration in Japan. Figure 3
Photograph of the Kawaguchi plant

bottom ash, after metals separation, is ground and fed back to the ash-melting furnace. In this way, over 97% of the waste input is transformed into energy, metals, and recyclable glass granulate.

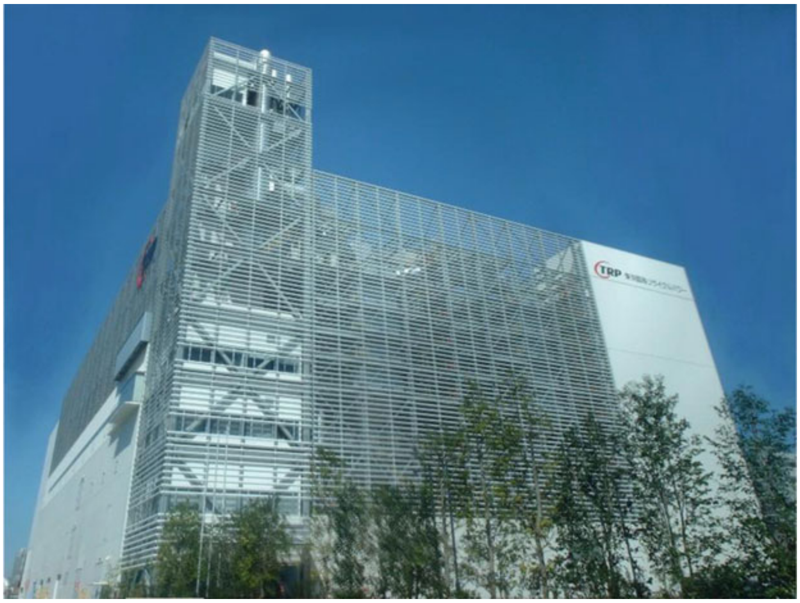
Figure 4 shows a photograph of the Tokyo Waterfront Recycle Power plant located in Tokyo Bay area, and treating 22.9 t/h of industrial waste in two process lines. In this plant, industrial wastes (plastic wastes and crushed/separated residue of construction wastes) are received in shredded form. Ash is melted under high temperatures into slag that is granulated and used as construction material. This plant generates 23 MW of electricity by recovering the heat generated in this plant and in another facility, next to this plant, in which medical wastes are treated.

The JFE High-Temperature Gasifying and Direct Melting Process

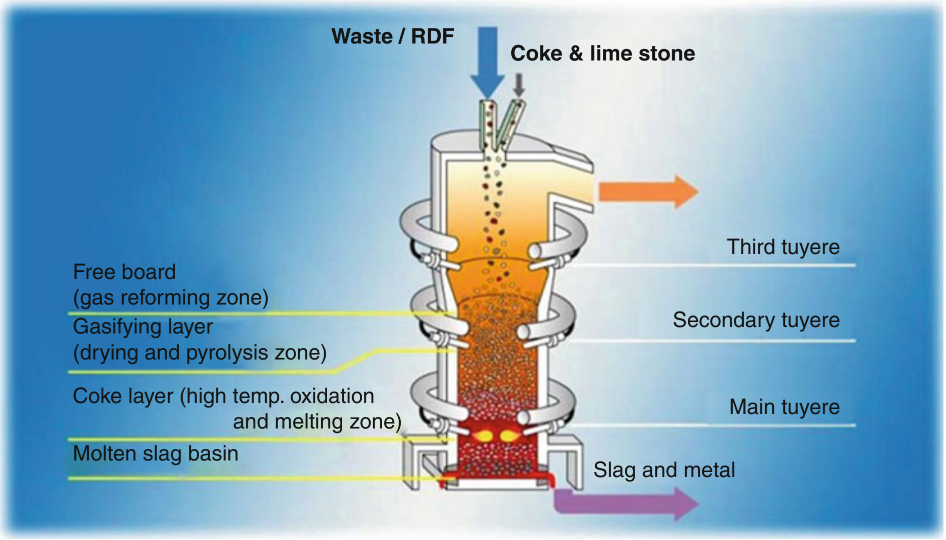
Process Description

JFE is a new company resulting from the merger of Nippon Kokan (NKK) and Kawasaki Steel. The JFE High-Temperature Gasifying and Direct Melting Process (JFE Process) resembles a small iron blast furnace where wastes are fed through the top of a vertical shaft (Fig. 5).

Air is introduced into the furnace through primary, secondary, and tertiary tuyeres located along the height of the shaft. The primary air, near the bottom of the shaft, is enriched to about 35% oxygen in order to generate the high temperatures required to transform the ash to molten slag and metal. In the gasifying zone, the gas produced in the lower part is partially combusted at approximately 600°C by an air sent through the secondary tuyeres while maintaining a fluidized state. By means of this heat, the wastes charged from the furnace top are preheated and thermally decomposed. Also, the fluidization ensures the downward flow of the bed within the shaft. In the gas reforming zone ("freeboard"), a tertiary air flow is injected to maintain the freeboard outlet temperature at 850°C and decompose organic gases and tar in reducing atmosphere. Ample space in the free board stabilizes the gas flow and reduces the velocity resulting in lower dust carryover in the gas flow. The slag and metal overflow from the furnace are quenched in



Gasification and Liquefaction Alternatives to Incineration in Japan. Figure 4
Photograph of the Tokyo waterfront recycle power plant



Gasification and Liquefaction Alternatives to Incineration in Japan. Figure 5
JFE High temperature gasifying and direct melting process

a water tank to form small spherical particles of granulated slag and metal.

The process requires the addition of coke (less than 5% of wastes), which is also added at the top of the shaft along with sufficient lime to form a fluid slag at the bottom of the furnace. The JFE Process produces slag and metal globules that are used beneficially, and fly ash which contains volatile metals and is landfilled.

Commercial Operation Experience

Up to 2010, JFE has delivered ten Direct Smelter plants in Japan, as shown in Table 2 [2]. All of them process as-received MSW except for the Fukuyama plant where RDF is combusted. The most recent plant serves the Chikushino/Ogori/Kiyama association in Fukuoka Prefecture (Kyushu) introduced. This plant is called "Clean-Hill Homan" and will be described in the following sections.

An Example of the Performance of the JFE Direct Melting Process

Figure 6 shows the process flowsheet and Fig. 7 is a photograph of the most recent JFE Direct Smelting plant at Fukuoka.

Table 3 shows the principal components of the Fukuoka plant.

Table 4 shows the mass balance of this plant in 2008. The total weight of MSW treated was 49,348 t and the slag, metal, and fly ash were 11.1%, 0.7%, and 2.3% of the solids feed, respectively. The use of the cyclone shown in Fig. 6 reduced the amount of fly ash significantly. All the slag recovered was utilized as a secondary concrete material or as a sub-base in road construction. The metal and fly ash recovered were also recycled.

Table 5 shows the electric power balance including the power usage in the recycling center of this plant. The 49,000 t of MSW generated 22,000 MWh of electricity of which 9.100 MWh were sold to the grid.

Table 6 shows the exhaust gas emission data along with the national standards. All the emission data were well below the regulation values.

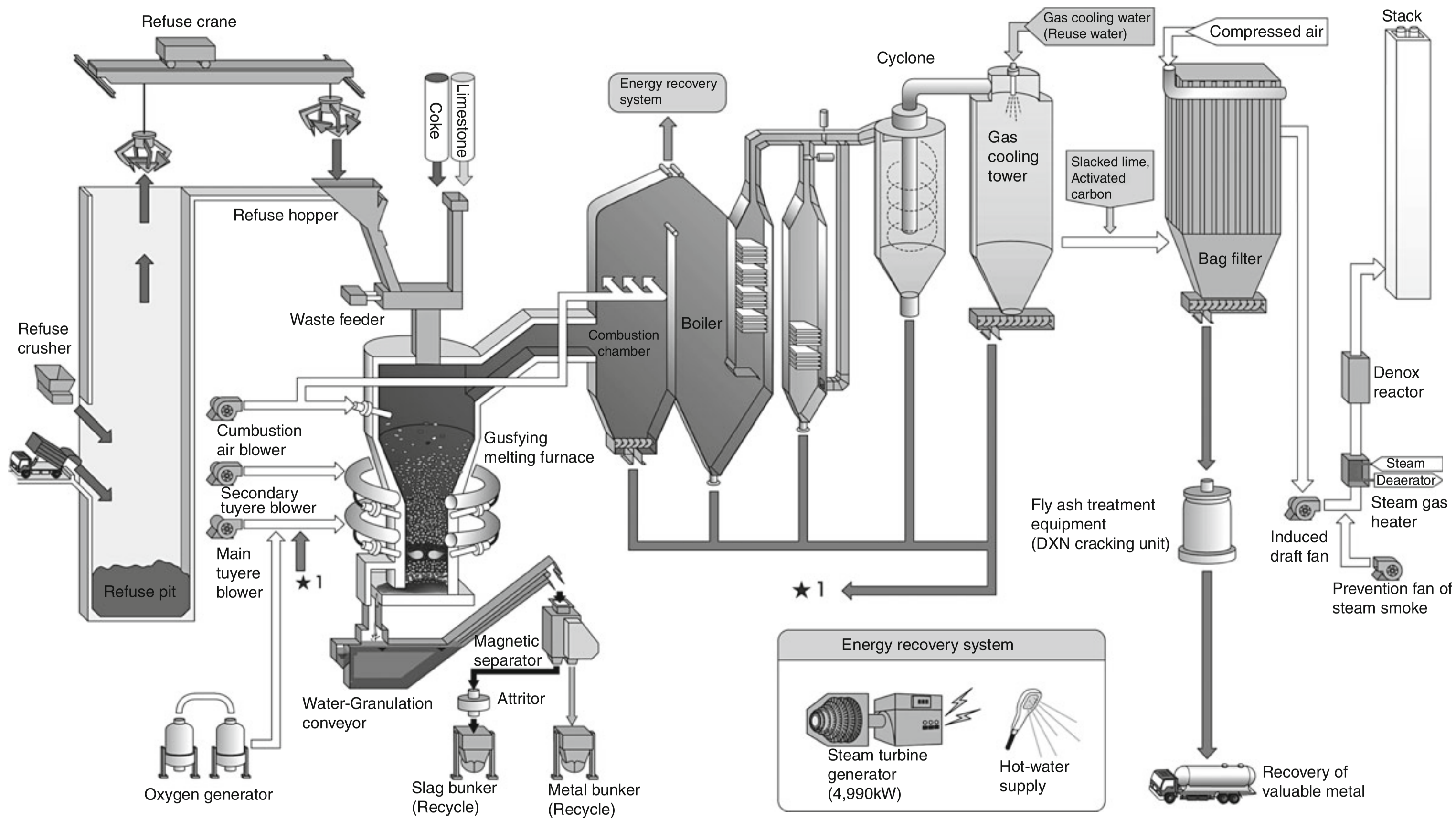
Table 7 compares the results of leachability and concentration tests for various metallic contaminants with the standard values of Japan. It can be seen that in all cases the test data were substantially below the standard values.

Slag Utilization

Japanese government has a policy of encouraging the vitrification of ash ((bottom ash to slag) as part of the hierarchy of waste management and for extending landfill life. Therefore, the production of slag has been increased remarkably during the last 10 years. Slag is standardized by JIS (Japan Industrial Standard) for usage as asphalt and concrete aggregate. As a result, slag utilization is progressing and a considerable

Gasification and Liquefaction Alternatives to Incineration in Japan. Table 2 List of operational JFE process plants

	Municipality/owner	Capacity × Line	Input waste	Completion
1	Kagamihara City, GIFU	192 t/day (64 t/day × 3)	MSW (incl. bulky wastes)	2003.03
2	Amagi/Asakura/Mitsui Association, FUKUOKA	120 t/day (60 t/day × 2)	MSW (incl. bulky wastes)	2003.03
3	Hidaka-chubu Association, HOKKAIDO	38 t/day (19 t/day × 2)	MSW (incl. bulky wastes)	2003.02
4	Morioka/Shiwa Area Association, IWATE	160 t/day (80 t/day × 2)	MSW (incl. bulky wastes)	2003.03
5	Saiki Area Association, OITA	110 t/day (55 t/day × 2)	MSW (incl. bulky wastes)	2003.03
6	Fukuyama Recycle Power Corp., HIROSHIMA	314 t/day (314 t/day × 1)	RDF	2004.02
7	Ibaraki Environment Protection Foundation, IBARAKI	145 t/day (72.5 t/day × 2)	MSW and industrial waste (incl. bottom ash)	2006.03
8	Aki Area Association, KOCHI	80 t/day (40 t/day × 2)	MSW (incl. bulky wastes, landfill-wastes)	2006.03
9	Hamada Area Association, SHIMANE	98 t/day (49 t/day × 2)	MSW (incl. bulky wastes)	2006.11
10	Chikushino/Ogori/Motoyama Association, FUKUOKA	250 t/day (125 t/day × 2)	MSW (incl. bulky wastes, disaster wastes)	2008.03



Gasification and Liquefaction Alternatives to Incineration in Japan. Figure 6
Process flowchart of the Clean-Hill Homan plant

Gasification and Liquefaction Alternatives to Incineration in Japan. Figure 7
Photograph of the Clean-Hill Homan plant

Gasification and Liquefaction Alternatives to Incineration in Japan. Table 3 Outline of the clean-hill homan plant

Capacity	250 t/day (125 t/day × 2 Furnaces)
Furnace type	Shaft melting process (high temperature gasifying and direct melting furnace)
Energy recovery system	Boiler 22.0 t/h, 400°C × 3.92 MPa, steam turbine generator (4 990 kW), hot-water supply system
Exhaust gas treatment system	Cyclone, bag filter, Denox reactor
Slag treatment system	Water-granulation conveyor, magnetic separator, attritor
Fly ash treatment system	Dioxins cracking unit

fraction of slag has acquired an economic value. Figure 8 shows the increase in number of ash-melting furnace plants with time. Figure 9 also shows that both the tonnage of slag produced and the slag used beneficially have increased with time.

The various uses to which the slag is put are shown graphically in Fig. 10.

The TOSHIBA Process for Liquefaction of Plastic Wastes

Social Background

The Plastic Waste Management Institute of Japan reported [3, 4] that the domestic plastic waste produced in 2006 had reached a total of 10 million tons, made up of about 5 million tons of household waste and another 5 million tons of industrial waste. Of this waste, 72% (7.21 million tons) was reutilized as materials, fuels, electricity, or heat, among others. However, 28% (2.84 million tons) was incinerated without energy recovery or landfilled. According to the Japan Containers and Packaging Recycling Association [5], the quantity of plastic containers and wrapping, within household plastic wastes was 550,000 t. Of this amount, 23% (130,000 t) was used in materials recycling operations and 46% (250,000 t) in chemical recycling operations, under the Container and Packaging Recycling Law; the remaining 31% was incinerated or landfilled. The breakdown of chemical recycling activities (250,000 t) in 2006 were coke ovens (61%), gasification (22%), blast furnaces (15%), and liquefaction (2%). The waste plastics liquefaction operations of the Sapporo Plastics Recycling Co., Ltd. (SPR) are classified as a chemical recycling technique in Japan. Two plastic

Gasification and Liquefaction Alternatives to Incineration in Japan. Table 4 Mass balance of MSW disposal (total MSW disposal was 49,348 t)

Recovered material	Amount of emergence (t)	Ratio (wt%)
Slag	5,502	11.1
Metal	352	0.7
Fly ash	1,116	2.3

Gasification and Liquefaction Alternatives to Incineration in Japan. Table 5 Electric power balance (Including recycling center)

Item	Electric power (MWh)
Generated	22,349
Purchased	989
Sold	9,070
Consumed	14,268

Gasification and Liquefaction Alternatives to Incineration in Japan. Table 6 Exhaust gas emission data

Item	Regulation value	Analysis value
Dust (g/m^3N)	<0.02	<0.005
SOx (ppm)	<50	0.3–6.0
NOx (ppm)	<50	6.0–32.0
HCl (ppm)	<50	<8.6
CO (ppm)	<30	2–7
Dioxins (ng-TEQ/m^3N)	<0.05	0.00000009–0.0048

liquefaction facilities have been operating commercially in Japan: the Niigata Plastics Liquefaction Centre (6,000 t/year) and the Sapporo Waste Plastics Liquefaction Plant (14,800 t/year). The waste plastics liquefaction technique is different to other recycling techniques, and, after overcoming initial problems, SPR process has maintained high levels of safety, stability, and productivity.

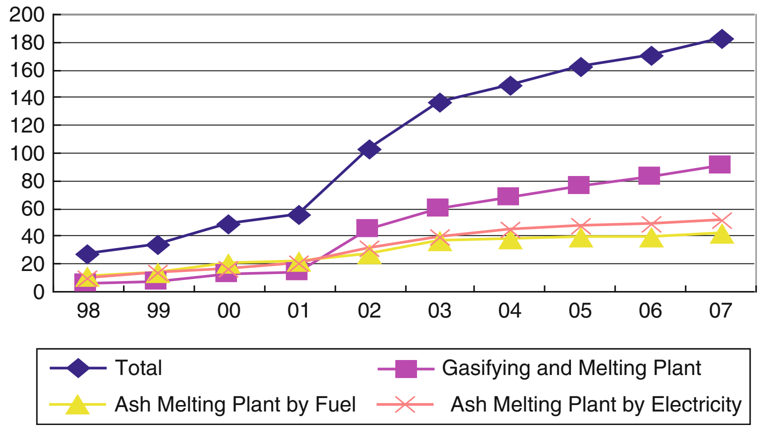
Gasification and Liquefaction Alternatives to Incineration in Japan. Table 7 Result of slag measurement (example)

	Elution (standard value, mg/l)	Content (standard value, mg/kg)
Cd	<0.005 (<0.01)	<10 (<150)
Pb	<0.005 (<0.01)	<10 (<150)
Cr^{6+}	<0.04 (<0.05)	<10 (<250)
As	<0.005 (<0.01)	<10 (<150)
T-Hg	<0.0005 (<0.005)	<0.1 (<15)
Se	<0.005 (<0.01)	<10 (<150)
F	<0.08 (<0.8)	<150 (<4,000)
B	<0.1 (<1.0)	<150 (<4,000)

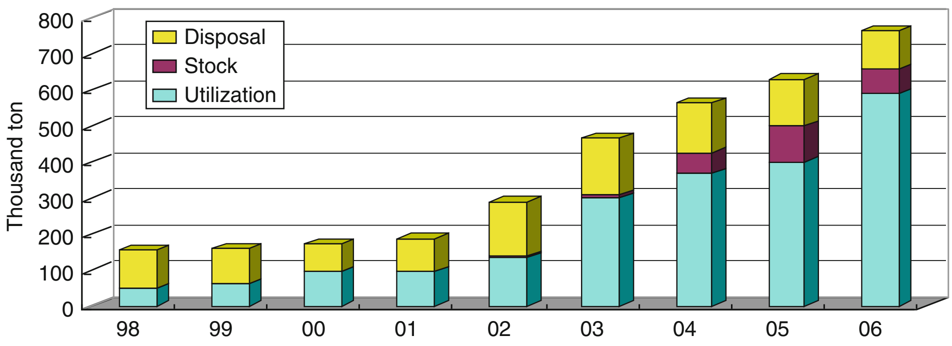
Process Description

In 2000, SPR started operating a liquefaction process that includes the unique characteristic of dechlorination of plastic wastes that contain polyvinylchloride chloride (PVC). The flowsheet of the SPR plastic waste liquefaction process is shown in Fig. 11. In the pretreatment stage, bales of compacted waste plastics are shredded and then foreign materials, such as pieces of metal and water are removed, and the remaining plastics are pelletized. The pellets are then fed into the dechlorination process where they are heated electrically to 300–330°C, melted, and the hydrochloric gas resulting from the thermal decomposition of PVC is incinerated at 1,200°C in dechlorinating furnace; scrubbing of this gas yields a solution containing less than 20% HCl which is sold. The molten polymer that is obtained in the dechlorination process is fed into the pyrolysis reactor where it is heated at 400–450°C for about 10 h and separates into a gaseous product that is conveyed to the distillation process and a residue that is fed to the solid fuel production process.

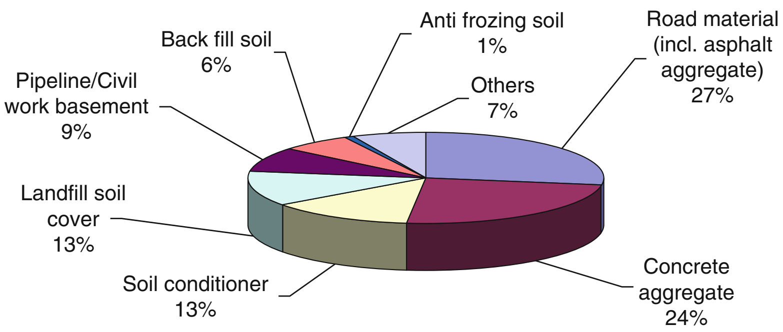
The gaseous product of the pyrolysis reactor is liquefied by spray quenching at 120°C, and the resulting pyrolysis oil is fed into the distillation tower where it is separated into three fractions: light oil at 120°C, "medium" oil at 200°C, and heavy oil at 280°C. The remaining volatile hydrocarbon gas is used as fuel in the plant operation. Some of the light oil product is



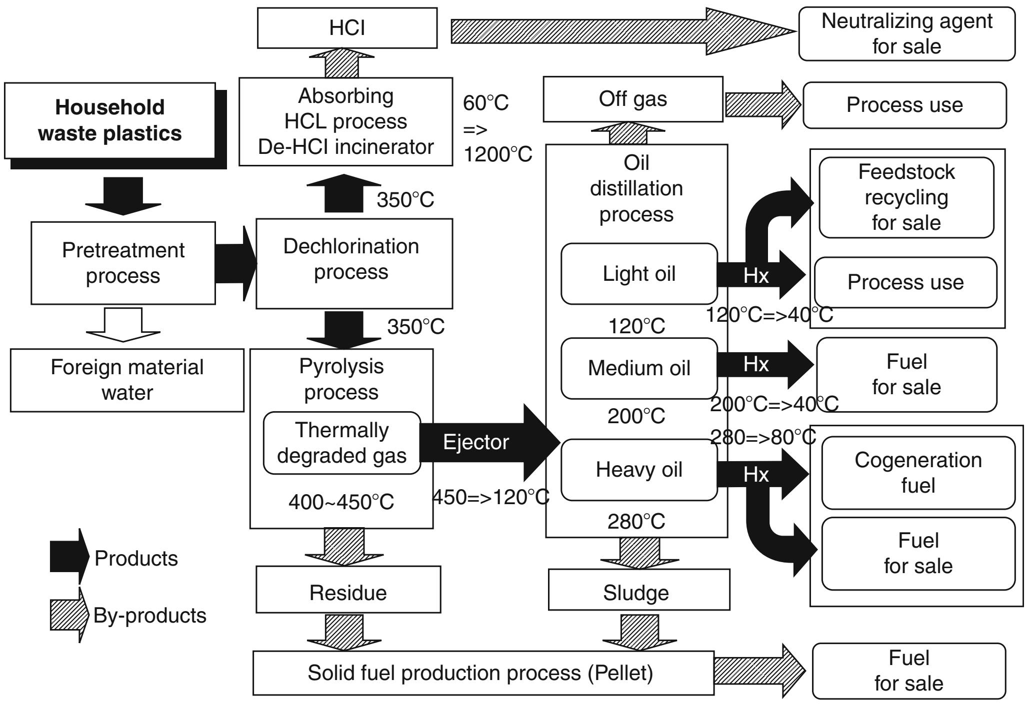
Gasification and Liquefaction Alternatives to Incineration in Japan. Figure 8
Increase in number of ash melting furnace plants



Gasification and Liquefaction Alternatives to Incineration in Japan. Figure 9
Increase of slag production and beneficial use



Gasification and Liquefaction Alternatives to Incineration in Japan. Figure 10
Beneficial uses of slag



Gasification and Liquefaction Alternatives to Incineration in Japan. Figure 11
Flowsheet of the Sapporo plastics recycling (SPR) plastics liquefaction process. *Hx* Heat exchanger

used as a raw material for manufacturing plastic and the rest is used as fuel in the plant. The "medium" oil is sold to local companies and used as boiler fuel. Some of the heavy oil product is provided to local central heating and air-conditioning companies, paper manufacturing companies, and other companies and used as fuel, and the rest is used to power cogeneration diesel engines. The sludge residue derived from the filtering of the heavy oil is mixed with pyrolysis residues and used as a solid fuel. Almost all the plastic, except for the foreign material and water, is being reclaimed. As a result, in 2006, the recycling rate, excluding water contained in the feedstock bales, reached 96%.

Main Technical Challenges

In the first year of operation (2000), it was difficult to maintain normal processing due to corrosion and clogging due to the presence of polyethylene terephthalate (PET) in the plastic waste. The operational problems were due to the formation of benzoic acid (C_6H_5COOH) and terephthalic acid $C_6H_4(COOH)_2$, during the thermal decomposition of PET (Table 8). The cause of the problems was investigated and it was found that the organic acids were mainly formed in the operating temperature range between 170°C and 250°C. This problem was solved by adding hydrated lime [$Ca(OH)_2$] to the plastic waste pellets and plant operation was stabilized.

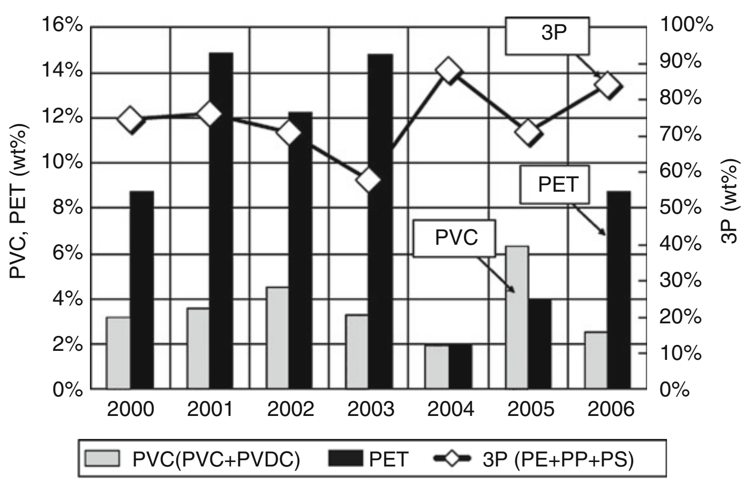
Composition of Raw Material and Properties of Reclaimed Products

The composition of typical municipal plastic waste is shown in Fig. 12. Polypropylene, polyethylene, and polystyrene (PP/PE/PS:3P), which are easily processed by liquefaction, make up 70–90% of the waste. However, PVC and PET constitute 2–7 t% and 2–15% of the waste, respectively. PVC causes corrosion and quality degradation of the recycled product, and PET can cause corrosion and clogging. Because the problems caused by corrosion and

Gasification and Liquefaction Alternatives to Incineration in Japan. Table 8 Influence of organic acids on the recycling process

	Temperature (°C)		Phase	Concentration (wt%)		Trouble (●; Serious)	
	In	Out		Benzoic acid	Terephthalic acid	Clogging	Corrosion
Heavy oil Hx (upper)	250	170	Liquid	<27	<1	●	None
Heavy oil Hx (lower)	170	80	Liquid	–	–	Minor	None
Fire heater tube	200	300	Liquid			None	●
Distillation tower (upper middle column)	210		Liquid	<90	<2	None	●
Distillation tower (middle column)	220		Liquid	<24	<15	None	●
Distillation tower (bottom column)	270		Liquid	<7	<3	Minor	None

Hx Heat exchanger, *wt%* weight percent



Gasification and Liquefaction Alternatives to Incineration in Japan. Figure 12
Composition of municipal waste plastics. *PET* polyethylene terephthalate, *PVC* polyvinylchloride, *PVDC* polyvinylidene chloride, *PE/PP/PS* polyethylene, propylene, polystyrene

clogging were overcome by the countermeasures mentioned above, the operation of the SPR process is presently stable and safe.

The properties of the reclaimed oil are shown in Table 9. The sulfur, nitrogen, and chlorine contents were below the limit values specified in Japanese Industrial Standards (JIS; technical specification Z 0025 for pyrolytic oil from waste plastics). The SPR reclaimed oil contains 0.003–0.08% sulfur (JIS level: 0.2%), 0.08–0.14% nitrogen (JIS level: 0.2%), and 50–70 ppm chlorine (JIS level: 100 ppm).

The properties of the solid fuel produced from waste plastics are shown in Table 10. Solid fuel pellets are produced from thermally degraded residue and heavy oil sludge. Inorganic chloride levels of 1–4% are found in the solid fuel because $CaCl_2$ is formed by reactions between hydrated lime [$Ca(OH)_2$, tat as noted above is added to the process to mitigate the problems caused by PET] and chlorine. Therefore, this solid fuel is used in a blend with other solid fuels (e.g., wood or coal) at low levels of a few percent (usually below 5%) to minimize environmental problems.

Gasification and Liquefaction Alternatives to Incineration in Japan. Table 9 Properties of the oils recovered in the SPR process

Property		Light oil	Medium oil	Heavy oil	JIS TS Z0025 (Japanese technical standard)
Density	g/cm3 (15°C)	0.814	0.824	0.856	
Flash point	°C	<21	78	114	
Pour point	°C	<−50	−35.0	47.5	
Reaction	pH	Neutral	Neutral	Neutral	
Ash	wt%	<0.001	<0.01	<0.01	≦0.05
Sulfur	wt%	0.002	0.03	0.08	≦0.2
Nitrogen	wt%	0.08	0.14	0.1	≦0.2
Chlorine	wtppm	50	70	60	≦100
Gross heating value	kj/kg	42,070	45,040	45,360	

Gasification and Liquefaction Alternatives to Incineration in Japan. Table 10 Properties of the solid fuel produced in the SPR process

Property	Solid fuel (eco pellet)	Degradation residue	Sludge
Lower heating value (kJ/kg)	15,160	17,570	31,650
Carbon (wt%)	41.8	45.6	67.5
Sulfur (wt%)	0.09	0.06	0.04
Nitrogen (wt%)	0.43	0.4	0.39
Hydrogen (wt%)	5.7	2.6	6.3
Calcium (mg/kg)	88,000	125,000	46,700
Silicon (mg/kg)	12,000	52,300	19,800
Aluminum (mg/kg)	13,000	12,700	940
Total chlorine (wt%)	2.82	4.96	1.42
Inorganic chlorine (wt%)	2.82	4.79	1.42
Bulk specific gravity (kg/l)	0.72	0.389	0.868

The measured results for gas emissions from the SPR off-gas-fired furnace are shown in Table 11. Some of the light oil is used as in-plant furnace fuel and the heavy oil for powering the cogeneration engines. According to periodic analysis of the gaseous emissions of these processes, nitrogen oxides (NOx), sulfur oxides (SOx), dust, dioxins, and HCl levels are below the required standards.

Development of Recycled Products and By-Products

In the SPR process, sludge is separated from the heavy oil by a centrifugal filtering method that was installed after initial operation; this resulted in much better quality of the heavy oil product of this process and, since then, heavy oil has been sold to other companies for use as a fuel. The light oil has been sold to a petrochemical company and is used as raw material for the production of naphtha since 2004. It is also used in the production of plastics. The Japanese recycling law considers only hydrocarbon oil as a recycled product; thermal degradation residue, off-gas (flammable gas), and hydrochloric acid are not considered as recycled products.

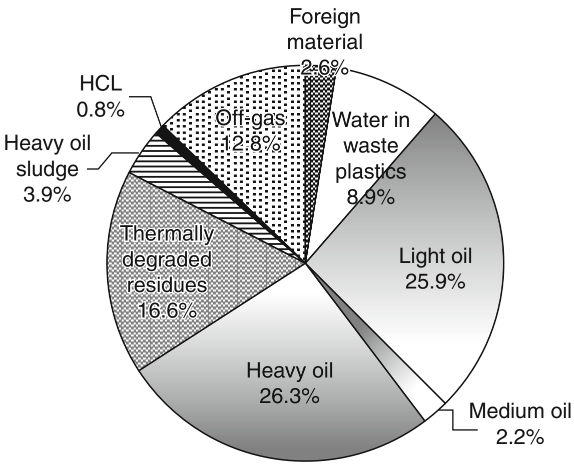
The off-gas of the SPR process has been reused as fuel within the plant since 2000. Initially, most of the thermal decomposition residue and oil sludge were discarded as industrial waste, but since 2004 they are supplied to other companies and are used as solid fuel. Hydrochloric acid, after neutralization, was initially discharged into the sewage system, but since 2004, it is also used by other companies as a neutralizer.

The actual recycling rate of the SPR plastics liquefaction plant in 2006 is shown in Fig. 13.

Gasification and Liquefaction Alternatives to Incineration in Japan. Table 11 Properties of gas emitted from the off-gas-fired furnace of the SPR waste plastics liquefaction plant

Periodic survery (twice a year)	Result of measurement	Emission standard	Date
Dust (particulates)	<0.02 g/Nm^3	0.15 g/Nm^3	2007/11/21
Sulfur oxide (SOx)	<0.05 Nm^3/h	3.12 Nm^3/h	2007/11/21
Nitrogen oxide (NOx)	95 vol ppm	150 vol ppm	2007/11/21
Optional survey			
Hydrogen chloride (HCl)	2.3 mg/Nm^3	80 mg/Nm^3	2004/1/13
Dioxin	0.000018 ng-TEQ/Nm^3	0.0006 ng-TEQ/Nm^3	2004/1/20

TEQ Toxicity equivalency quantity, *Nm3* Gas volume at 1 atm and 0°C



Gasification and Liquefaction Alternatives to Incineration in Japan. Figure 13
Actual recycling rate of the SPR plant in 2006

The recovered hydrocarbon oil amounted to 54.4% of the weight of the initial waste plastic; the gaseous fuel, solid fuel, and the hydrochloric acid products amounted to 35% of the weight of the initial waste plastic. Since SPR recycles almost all of the input waste plastics, except for the water and the foreign materials, a high recycling rate of 96%, excluding the water content, has been achieved (Fig. 13). Also, most of the recovered materials are reused in the local Hokkaido district; as a result, the resource recovery rate for local communities in Hokkaido has reached 93%.

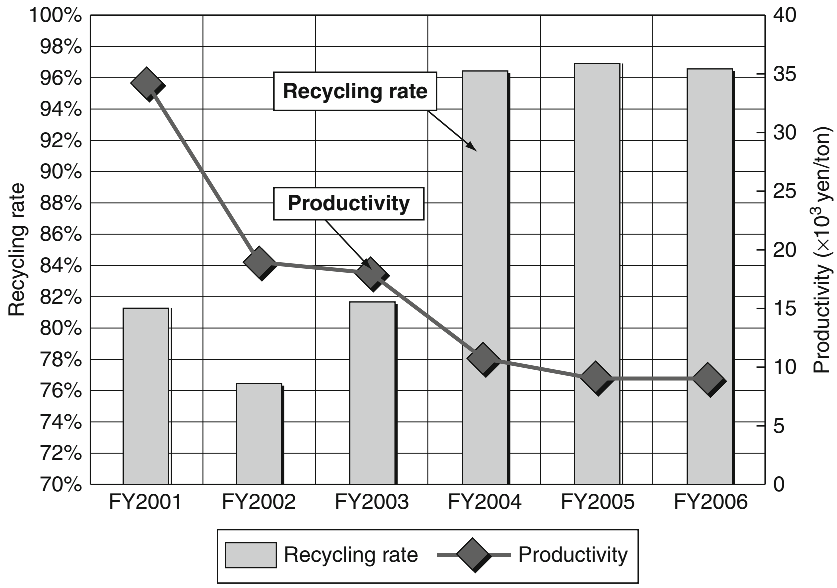
Productivity Improvement

The change in recycling rate and productivity with time of the SPR process are shown in Fig. 14. Productivity is expressed as the total operating cost of electric power, commercial fuel oil, and other supplies, etc.; these costs have decreased by a factor of three since the plant started operations in 2000. The measures that have contributed to productivity improvement are as follows:

- Reduction of hydrocarbon oil consumption during processing
- Reduction of amount of water used by producing and selling hydrochloric acid for use as neutralizer
- Reduction of industrial waste volume by selong solid fuel to others
- Introduction of an energy-saving burning system

Summary

Through its technological improvements and operational know-how, SPR has been able to process municipal waste plastics of almost all quality grades, even those containing PVC and PET. SPR can also process the sorted waste plastics from material recyclers or mechanical recyclers, thus allowing for a more efficient recycling of plastic waste that combines mechanical and chemical recycling. SPR has achieved an extremely high recycling rate (93% in 2006) from mixed plastic wastes and developed a system that allows for the use of the light oil product as a petrochemical raw material.



Gasification and Liquefaction Alternatives to Incineration in Japan. Figure 14
Annual trends of actual recycling rate and productivity

Future Directions

In direct comparison with the currently more common stoker grate incineration of MSW, the EBARA TwinRec and the JFE Direct Smetling processes offer a number of advantages: high recovery of metals and inert materials directly from the bottom ash and vitrification of fine ash particles into an inert construction material [1, 3].

These processes are based on gasification and require a lower amount of excess air, resulting in a compact air pollution control system. Also, as shown by the feedstock of the reference plants noted above, these processes are more flexible with regard to feedstock.

The processes described in this entry have demonstrated, through the range of capacity of commercial plants and the use of multiple feedstocks, that gasification of solid wastes is mature, reliable, efficient, and a good solution for current and future waste management applications.

Another approach to enhance the recycling of MSW is to segregate plastic materials and liquefy them, as demonstrated commercially by the SPR process. In the past it was difficult to recycle municipal waste plastics that contained PVC and PET. Thus, material recycling methods have traditionally sorted out only PP/PE/PS from municipal waste plastics and nearly one half were disposed as residue. The SPR commercial liquefaction plant has shown that it is possible to process mixed plastics containing PVC and PET. This plant has attained a very high recycling rate achieved a high recycling rate of 93% of the solids in the feedstock to the process.

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Geothermal Energy Utilization

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Article Outline

Glossary

Balneology The science of the healing qualities of baths, especially with natural mineral waters; the therapeutic use of natural, warm, or mineral waters.

Binary power plant Used with low-temperature resources (below 150°C or 300°F) where a secondary low boiling point working fluid (normally a hydrocarbon) is vaporized by the geothermal fluid through a heat exchanger to drive a turbine producing electricity. Also referred to as an organic Rankine cycle (ORC) machine.

Caldera A large basin-shaped volcanic depression, circular in form, with a diameter many times greater than the included volcanic vent usually causes by an explosive volcanic eruption that drains the magma chamber resulting in collapse of the volcano.

Calorie The quantity of heat needed to raise the temperature of 1 gram (g) of water by 1 degree centigrade (°C) at 16°C. It is equal to 4.185 J.

Cap rock A comparatively impervious stratum that prevents the circulation of heat or fluid.

Conduction The transfer of heat through a medium or body driven by a temperature gradient and involving no particle motion. The average temperature gradient of the world, caused by conduction is about 25°C/km increasing with depth above the mean annual surface temperature.

Convection A process of mass movements of portions of any fluid medium (liquid or gas) as a consequence of different temperatures in the medium and hence different densities moving the medium and also the heat.

Enhanced (engineered) geothermal systems (EGS) Extracting heat stored in rocks within about 10 km of the surface, from which energy cannot be economically extracted by natural hot water or steam. The system is hydrofractured and water pumped down one well, extracting the heat by flowing through the fractures, and producing hot water or steam through a second well.

Fault A fracture or fracture zone along which there has been displacement of the sides relative to one another parallel to the fracture. The movement can be vertical, horizontal, or a combination of the two.

Flash steam The steam generated when the pressure on hot water (usually above 100°C) is reduced.

Fossil fuel A deposit of organic material containing stored solar energy that can be used as fuel, such as coal, natural gas, and petroleum.

Fumarole A hole or vent from which fumes or vapors issue usually found in volcanic areas.

Geopressured Zones below depths of 1,800–3,000 m, in which sediments in basins are commonly characterized by abnormally high pressure, high temperature, and high salinity.

Geothermal energy The internal energy of the earth, usually from the radioactive decay of potassium, thorium, and uranium, often associated with magma bodies, available to humans as heat from heated rocks, water, or steam.

Geyser A spring that erupts with intermittent jets of heated water or steam.

Heat exchanger A device for transferring heat from one fluid to another. The fluids are usually separated by conducting walls of metal or plastic.

Heat flow Dissipation of heat coming from within the earth by conduction. The worldwide average is about 65 mW/m^2.

Heat pump A device which, by the consumption of work or heat, affects the transport of heat between a lower temperature to a higher temperature

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source. The useful output is heat in conventional usage. The reverse process is called a refrigerator used for the removal of heat.

Hot Spring A thermal spring whose water has a higher temperature than that of the human body (usually above 40°C).

Hydrothermal An adjective applied to heated or hot aqueous-rich solutions, to the processes of which they are concerned, and to the rocks, ore deposits, and alteration products produced by them.

Joule (J) The SI unit for all forms of energy or work. It is equal to 1 W-s or 0.239 cal.

Lava Hot fluid rock that issues from a volcano or a fissure in the earth's surface coming from subsurface magma.

Magma Molten rock within the earth from which an igneous rock results by cooling, and forms lava when it erupts on the earth's surface.

Permeability The capacity of a rock to transmit fluid, dependent upon the size and shape of the pores and their interconnections.

Seismic Pertaining to an earthquake or earth vibrations, including those that are artificially induced.

Spa A resort using mineral water for bathing, soaking, and drinking along with covering portions of the body with mineral muds for therapeutical purposes. Diet, exercise, and rest can also be part of the spa treatment plan.

Subsidence A sinking of a large part of the earth's crusts, often due to the removal of fluid by pumping.

Volcano A vent in the earth surface through which magma as lava and associated gases, and/or pyroclastic material (rock, cinders, pumice, and ash) erupt.

Watt (W) A unit of power or energy produced over time, equivalent to 1 J/s, or 0.001341 horse power (hp).

Definition and Importance of Geothermal Energy

Geothermal energy is the heat contained within the Earth that generates geological phenomena on a planetary scale. The main sources of this energy are due to the heat flow from the earth's core and mantel generated by the radioactive decay of potassium, thorium, and uranium in the crust or by friction heat generated in subduction zones along continental plate margins. It may be characterized by surface expression of fumaroles, hot springs, geysers, volcanic eruption, and lava flows. Geothermal energy is often used to indicate that part of the Earth's heat that can, or could, be recovered and exploited by humankind. The resource is large, is renewable in the broad sense, and is available almost everywhere in the world, depending upon the depth to the resource and the economics to produce it. The total estimated thermal energy above surface temperature to a depth of 10 km under the continents, reachable with current drilling technology, is 1.3×10^{27} J (1.3×10^{9} EJ = exajoules). Recovery of geothermal energy utilizes only a portion of the stored thermal energy due to limitations in rock permeability that permit heat extraction through fluid circulation, and to the minimum temperature limits for utilization at a given site. The recovery factor is estimated between 0.5% and 20% [1]; and at the lower rate, this is 6.5×10^{6} EJ, or about 200,000 TW-years (terawatt = 10^{12} W). This is about three times the annual world consumption for all types of energy, and about 130 times at the higher recovery rate.

Geothermal energy can be used over a range of temperature to supply electricity, and heat and cool for the benefit of humankind. The higher temperature (above 175°C) is traditionally used to produce electricity; however with the improvement in the organic Rankine cycle or binary power plants described later, the usable temperature has been reduced to around 100°C. Lower temperatures are used for direct heating and cooling, from industrial process heating, space heating, and cooling including district energy systems, the heating of greenhouses and aquaculture ponds, to heating swimming pools and spas, generally in the range of 40–150°C. Finally the lowest temperatures from 5°C to 30°C, available anywhere in the world at shallow depth (up to 300 m), can utilize geothermal heat pumps for space heating and cooling.

Introduction

Early humans probably used geothermal water that occurred in natural pools and hot springs for cooking, bathing, and to keep warm [2]. There is archeological evidence that the Indians of the Americas occupied sites around these geothermal resources for over

10,000 years to recuperate from battle and take refuge. Many of their oral legends describe these places and other volcanic phenomena. Recorded history shows uses by Romans, Japanese, Turks, Icelanders, Central Europeans, and the Maori of New Zealand for bathing, cooking, and space heating. Baths in the Roman Empire, the middle kingdom of the Chinese, and the Turkish baths of the Ottomans were some of the early uses of balneology, where body health, hygiene, and discussions were the social custom of the day. This custom has been extended to geothermal spas in Japan, Germany, Iceland, and countries of the former Austro-Hungarian Empire, the Americas, and New Zealand. Early industrial applications include chemical extraction from the natural manifestations of steam, pools, and mineral deposits in the Larderello region of Italy, with boric acid being extracted commercially starting in the late 1700s. At Chaudes-Aigues in the heart of France, the world's first geothermal district heating system was started in the fourteenth century and is still going strong. The oldest and still operating geothermal district heating project in the United States is on Warm Springs Avenue in Boise, Idaho, going on line in 1892 and providing space heating for up to 450 homes.

The first use of geothermal energy for electric power production started in Italy with experimental work by Prince Gionori Conti between 1904 and 1905. The first commercial power plant (250 kWe) was commissioned in 1913 at Larderello, Italy. These developments were followed by flash steam plants coming on line in New Zealand at Wairakei in 1958; an experimental plant at Pathe, Mexico, in 1959; and the first commercial plant at The Geysers in the United States in 1960. Japan followed with 23 MWe at Matsukawa in 1966. All of these early plants used steam directly from the earth (dry-steam fields), except for New Zealand, which was the first to use flashed or separated steam for running the turbines. The former USSR produced power from the first true binary power plant, 680 kWe using 81°C water at Paratunka on the Kamchatka peninsula – the lowest temperature ever reported used in the world for power generation from geothermal energy at that time. Iceland first produced power at Namafjall in northern Iceland, from a 3 MWe noncondensing turbine. These were followed by plants in El Salvador, China, Indonesia, Kenya, Turkey, Philippines, Portugal (Azores), Greece, and Nicaragua in the 1970s and 1980s. Later plants were installed in Thailand, Argentina, Taiwan, Australia, Costa Rica, Austria, Guatemala, Ethiopia, with the latest installations in Germany and Papua New Guinea. Recently in 2006, a 200 kW binary plant was started at Chena Hot Springs in Alaska using geothermal fluids at 74°C, the lowest temperature for electric power generation recorded to date [3].

Types of Geothermal Resources

Geothermal energy comes from the natural heat of the earth primarily due to the decay of the naturally radioactive isotopes of uranium, thorium, and potassium. Because of the internal heat, the Earth's surface heat flow averages 65 mW/m^2 which amounts to a total heat loss of about 44 million megawatts (1,400 EJ/year). The estimated total thermal energy above surface temperature to a depth of 10 km, the limit of the deepest exploration drilling, is 1.3×10^{27} J (1.3×10^{9} EJ), equivalent to burning 3.0×10^{17} barrels of oil. Since the global energy consumptions for all types of energy is equivalent to the use of about 100 million barrels of oil per day, the Earth's energy to a depth of 10 km would supply all of humankind's energy needs for six million years [4].

On average, the temperature of the Earth with depth increases about 25°C/km above the surface ambient temperature. Thus, assuming a conductive gradient, the temperature of the earth at 10 km would be over 250°C. However, most geothermal exploration and use occurs where the gradient is higher, and thus where drilling is shallower and less costly. These shallow depth geothermal resources occur due to: (1) intrusion of molten rock (magma) from depth, bringing up great quantities of heat; (2) high surface heat flow, due to a thin crust and high-temperature gradient; (3) ascent of groundwater that has circulated to depths of several kilometers and been heated due to the normal temperature gradient; (4) thermal blanketing or insulation of deep rocks by thick formation of such rocks as shale whose thermal conductivity is low; and (5) anomalous heating of shallow rock by decay of radioactive elements, perhaps augmented by thermal blanketing [4].

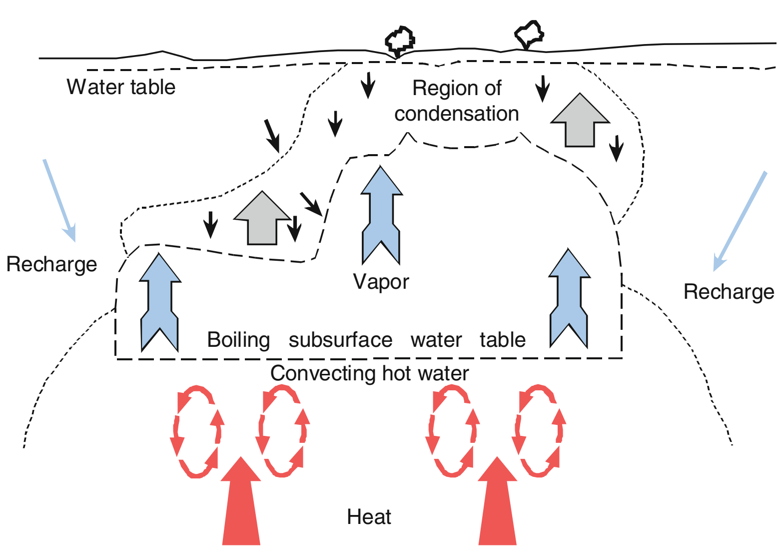
Geothermal resources are usually classified as shown in Table 1, modeled after White and Williams [5]. These geothermal resources range from the mean

annual ambient temperature of around 20°C to over 300°C. In general, resources above 150°C are used for electric power generation, although power has recently been generated at Chena Hot Springs Resort in Alaska using a 74°C geothermal resource [3]. Resources below 150°C are usually used in direct-use projects for heating and cooling. Ambient temperatures in the 5–30°C range can be used with geothermal (ground-source) heat pumps which provide both heating and cooling.

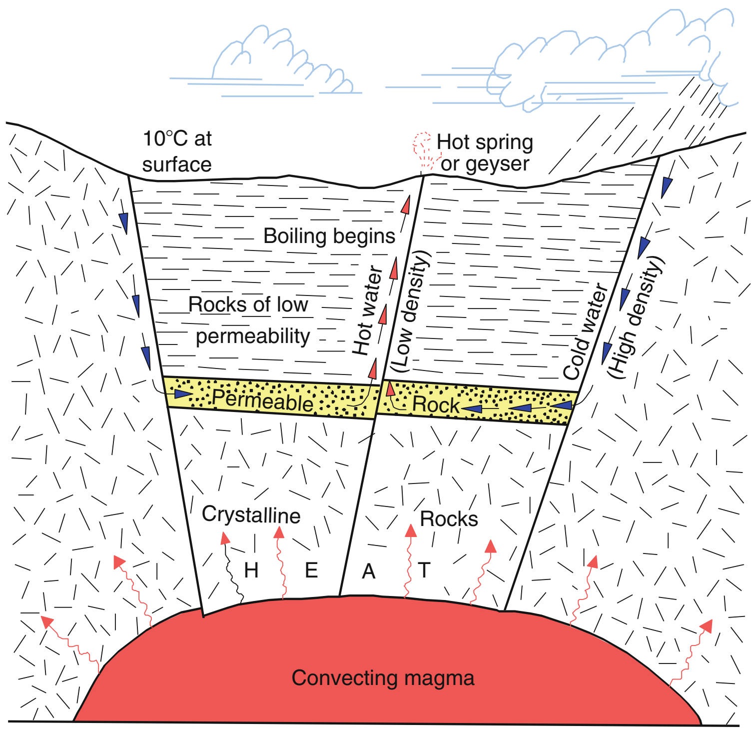
Convective hydrothermal resources occur where the Earth's heat is carried upward by convective circulation of naturally occurring hot water or steam. Underlying some high-temperature convective hydrothermal resources are temperatures of 500–1,000°C from molten intrusions of recently solidified rocks. The lower temperature resource results from deep circulation of water along fractures. *Vapor-dominated systems* (Fig. 1) produce steam from boiling of deep, saline waters in low permeability rocks. These reservoirs are few in number, with The Geysers in northern California, Larderello in Italy, and Matsukawa in Japan being ones where the steam is exploited to produce electric energy. *Water-dominated systems* (Fig. 2) are produced by ground water circulating to depth and ascending from buoyancy in permeable reservoirs that are a uniform temperature over large volumes. There is typically an upflow zone at the center of each convection cell, an outflow zone or plume of heated water moving laterally away from the center of the system, and a downflow zone where recharge is taking place. Surface manifestations include hot springs, fumaroles, geysers, travertine deposits, chemically altered rocks, or sometimes, no surface manifestations (a blind resource).

Geothermal Energy Utilization. Table 1 Geothermal resource types

Resource type	Temperature range (°C)
Convective hydrothermal resources	
Vapor dominated	≈240°
Hot water dominated	20° to 350°+
Other hydrothermal resources	
Sedimentary basin	20° to 150°
Geopressured	90° to 200°
Radiogenic	30° to 150°
Hot rock resources	
Solidified (hot dry rock)	90° to 650°
Part still molten (magma)	>600°



Geothermal Energy Utilization. Figure 1
Vapor-dominated geothermal system



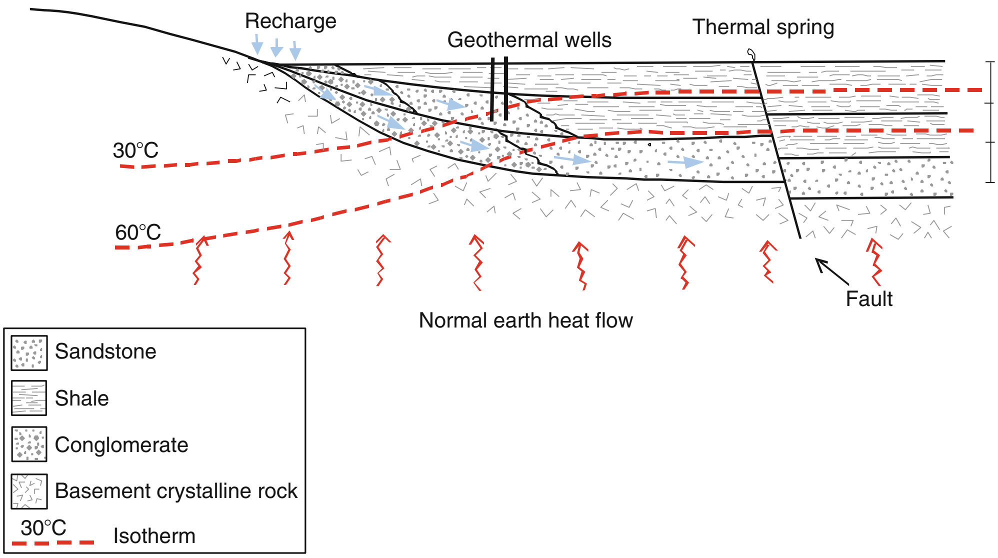
Geothermal Energy Utilization. Figure 2
Hot water–dominated geothermal system

Sedimentary basins (Fig. 3) produce higher temperature resources than the surrounding formations due to their low thermal conductivity or high heat flow or both producing geothermal gradients >30°C/km. These generally extend over large areas and are typical of the Madison Formation of North Dakota, South Dakota, Montana, and Wyoming area of the northern United States and the Pannonian Basin of Central Europe where it has been used extensively in Hungary.

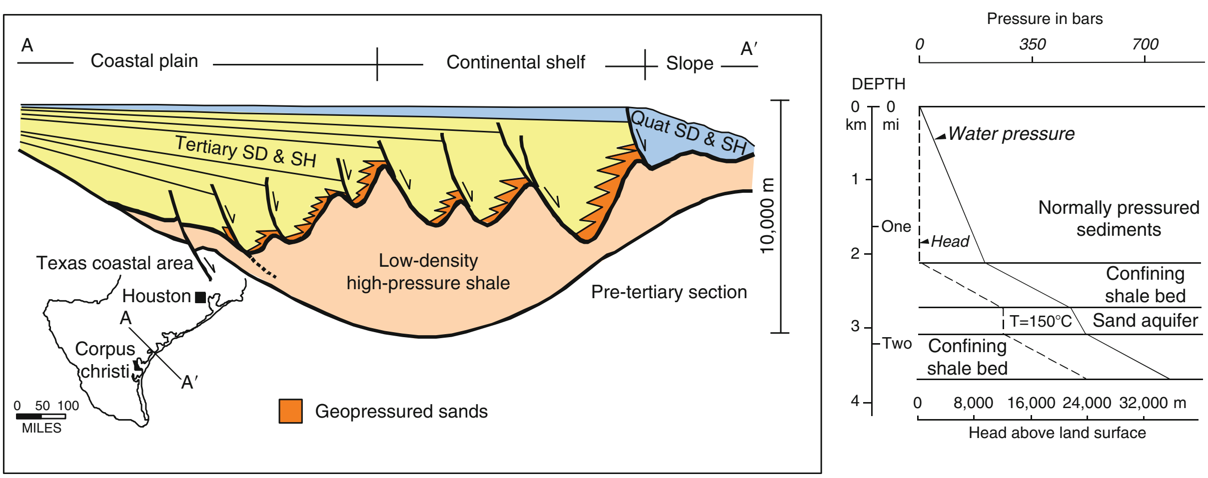
Geopressured resources (Fig. 4) occur in basin environments where deeply buried fluids contained in permeable sedimentary rocks warmed in a normal or enhanced geothermal gradient by their great burial depth. The fluids are tightly confined by surrounding impermeable rock and bear pressure much greater than hydrostatic. Thermal waters under high pressure in sand aquifers are the target for drilling, mainly as they contain dissolved methane. The source of energy available from this type of resources consists of: (1) heat, (2) mechanical energy, and (3) methane. The Texas and Louisiana Gulf Coast in the United States has been tested for the geothermal energy; however, due to the great depths of several kilometers, they have not proved economic, but are currently being evaluated again.

Radiogenic resources (Fig. 5) are found where granitic intrusions are near surface heating up the local groundwater from the decay of radioactive thorium, potassium, and uranium. This localized heating increases the normal geothermal gradient providing hot water at economical drilling depths. This type of resource occurs along the eastern United States, but has not been developed commercially.

Hot dry rock resources (Fig. 6) are defined as heat stored in rocks within about 10 km of the surface from which energy cannot be economically extracted by natural hot water or steam. These hot rocks have few pore space or fractures, and therefore, contain little water and little or no interconnected permeability. In order to extract the heat, experimental projects have artificially fractured the rock by hydraulic pressure, followed by circulating cold water down one well to extract the heat from the rocks and then producing from a second well



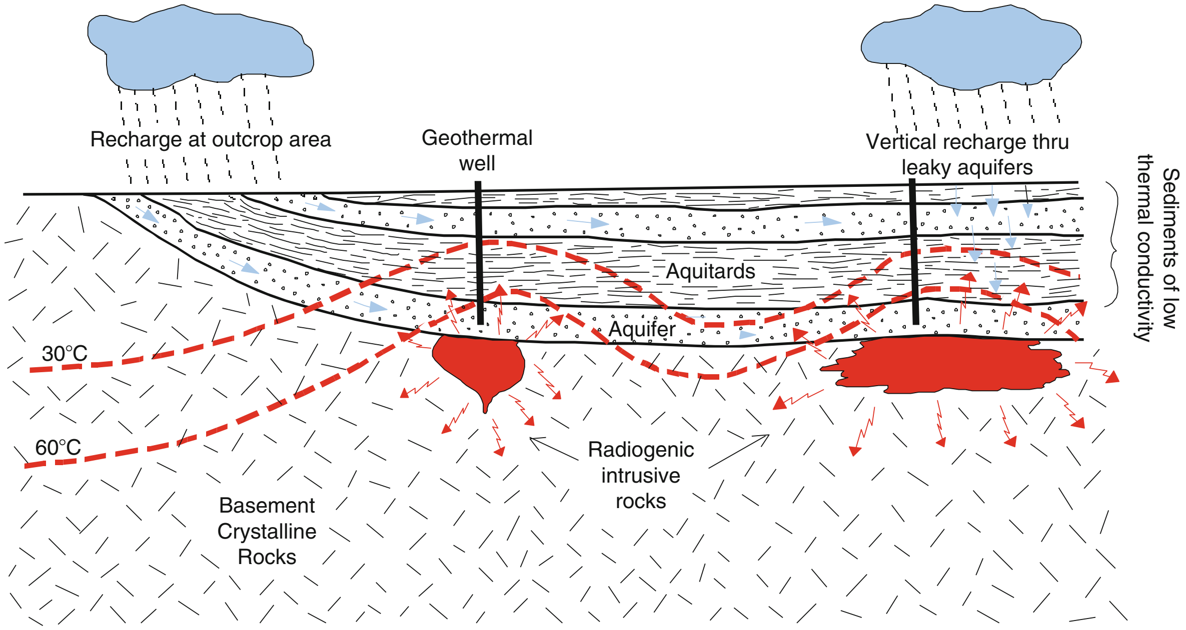
Geothermal Energy Utilization. Figure 3
Sedimentary basin geothermal resource



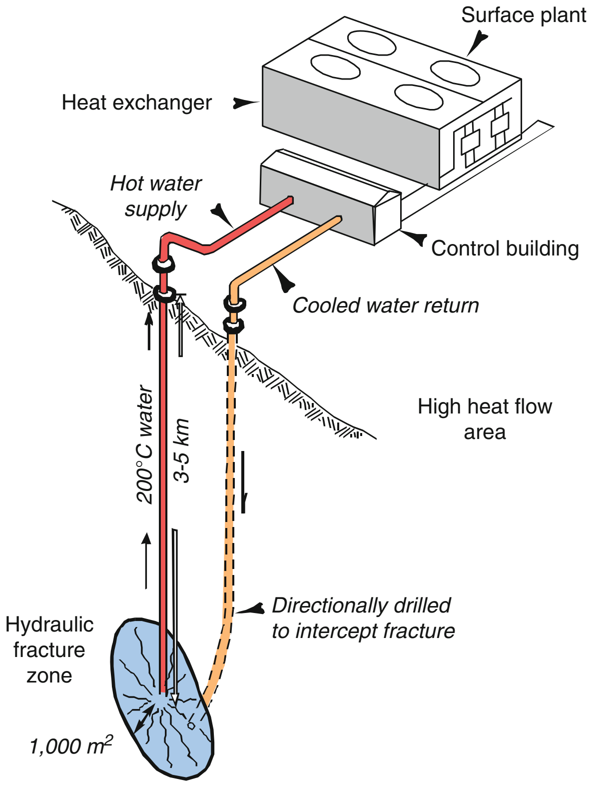
Geothermal Energy Utilization. Figure 4
Geopressured geothermal system

in a closed system. Early experimental projects were undertaken at Fenton Hill (Valdes Caldera) in northern New Mexico and on Cornwall in southwest England; however, both of these projects have been abandoned due to lack of funds and poor results. Projects are currently underway in Soultz-sous-Forêt in the Rhine Graben on the French–German border, in Germany at Bad Urach, several locations in Japan, and in the Cooper Basin of Australia [6]. Renewed interest has been generated in the United States for enhanced (engineered) geothermal systems (EGS) based on a recent MIT report [7].

Molten rock or *magma resources* have been drilled in Hawaii experimentally to extract heat energy directly from molten rock. It has been used successfully at Heimaey in Iceland (one of the Westmann Islands)



Geothermal Energy Utilization. Figure 5
Radiogenic geothermal system



Geothermal Energy Utilization. Figure 6
Hot dry rock exploitation

after the 1973 eruption. A heat exchanger constructed on the surface of the lava flow recovered steam resulting from boiling of downward percolation water from the surface. The heat was used in a space-heating system for over 10 years, but is now shutdown due to cooling of the surrounding rock.

Utilization in 2010

Based on 68 country update papers submitted to the World Geothermal Congress 2010 (WGC2010) held in Bali, Indonesia, the following figures on worldwide geothermal electric and direct-use capacity are reported. A total of 78 countries have reported some utilization from WGC2000, WGC2005, and WGC2010 electric, direct use, or both [8–12] (Table 2).

The figures for electric power capacity (MWe) appear to be fairly accurate; however, several of the country's annual generation values (GWh) had to be estimated which amounted to only 0.5% of the total. The direct-use figures are less reliable and probably are understated by as much as 20%. The author is also aware of at least five countries, which utilize geothermal energy for direct-heat applications, but did not

submit reports to WGC2010. The details of the present installed electric power capacity and generation, and direct use of geothermal energy can be found in Bertani [12] and Lund et al. [10]. These data are summarized in Table 3.

A review of the above data show that for electric power generation each major continent has approximately the same percentage share of the installed capacity and energy produced with the Americas and Asia having over 75% of the total; whereas with the direct-use figures, the percentages drop significantly from installed capacity to energy use for the Americas (28.9–18.4%) due to the high percentage of geothermal heat pumps with low capacity factor for these units in the United States and Canada. On the other hand, the percentages are approximately equal for the remainder of the world due to a lesser reliance on geothermal heat pumps, and the greater number of operating hours per year for these units.

Geothermal Energy Utilization. Table 2 Total geothermal capacity and use in 2010

Installed annual				
Use	Power (MW)	Energy use (GWh/year)	Capacity factor	Countries reporting
Electric power	10,715	67,246	0.72	24
Direct use	50,583	121,696	0.27	78

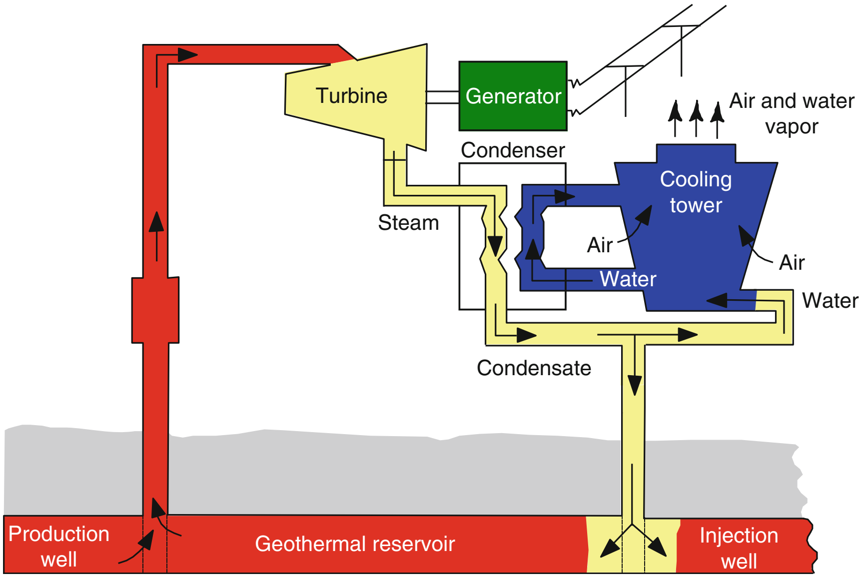
Electric Power Generation

Geothermal power is generated by using steam or a hydrocarbon vapor to turn a turbine-generator set to produce electrons. A vapor-dominated (dry steam) resource (see Figs. 1 and 7) can be used directly, whereas a hot water resource (see Figs. 2 and 8) needs to be flashed by reducing the pressure to produce steam. In the case of low-temperature resource, generally below 150°C, they require the use of a secondary low boiling point fluid (typically a hydrocarbon) to generate the vapor, in a binary or organic Rankine cycle plant (see Fig. 9). Usually a wet or dry cooling tower is used to condense the vapor after it leaves the turbine to maximize the temperature and pressure drop between the incoming and outgoing vapor and thus increase the efficiency of the operation. The worldwide installed capacity has the following distribution: 27% dry steam, 41% single flash, 22% double flash, 12% binary/combined cycle/hybrid, and 1% backpressure [12].

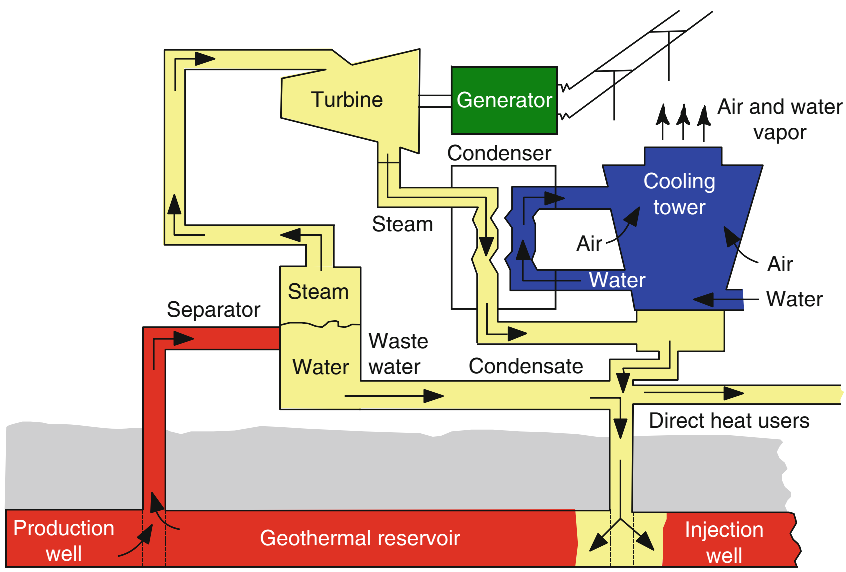
Electric power has been produced from geothermal energy in 27 countries; however, Greece, Taiwan, and Argentina have shut down their plants due to environmental and economic reasons. Since 2000, the installed capacity in the world has increased almost 3,000 MWe. Since 2000, additional plants have been installed in Costa Rica, France on Guadeloupe in the Caribbean, Iceland, Indonesia, Kenya, Mexico, and Philippines. In 2004, Germany installed a 210-kWe binary plant at Neustadt Glewe and 56-MWe plants have been installed on Papua New Guinea to generate electricity for a remote mine. Russia has completed a new 50-MWe plant on Kamchatka. More recently, a 200 kW binary

Geothermal Energy Utilization. Table 3 Summary of regional geothermal use in 2010

Electric power				Direct use		
Region	%MWe	%GWh/year	#countries	%MWt	%GWh/year	#countries
Africa	1.6	2.1	2	0.1	0.6	7
Americas	42.6	39.9	6	28.9	18.4	15
Asia	34.9	35.1	6	27.5	33.8	16
Europe	14.5	16.2	7	42.5	45.0	37
Oceania	6.4	6.7	3	1.0	2.2	3

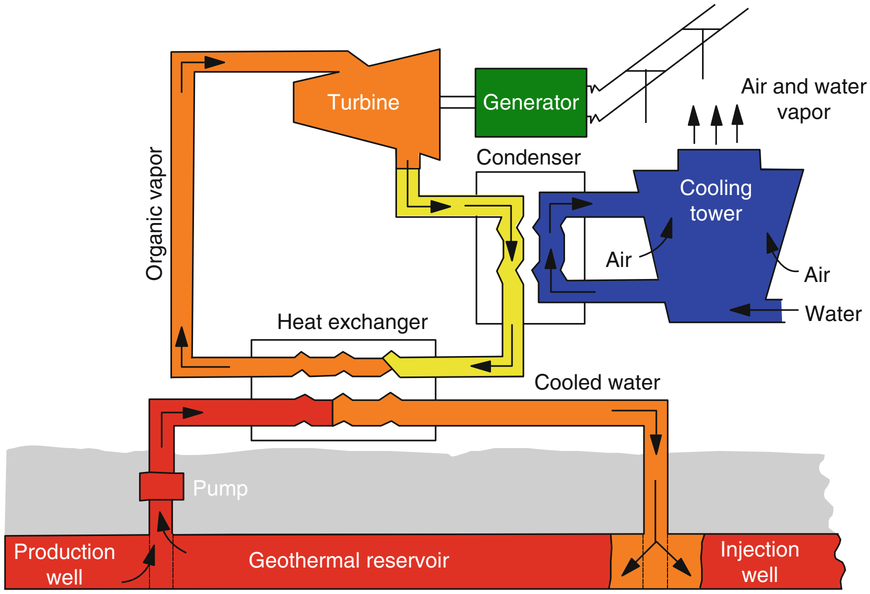


Geothermal Energy Utilization. Figure 7
Steam plant using a vapor- or dry-steam-dominated geothermal resource



Geothermal Energy Utilization. Figure 8
Flash steam plant using a water-dominated geothermal resource with a separator to produce steam

plant using 74°C geothermal water and 4°C cooling was installed at Chena Hot Springs Resort in Alaska [3]. The operating capacity in the United States has increased since 1995 due to completion of the two effluent pipelines injecting treated sewage water at The Geysers. In an attempt to bring production back, the Southeast Geysers Effluent Recycling Project is now injecting 340 l/s of treated wastewater through a 48-km long pipeline from Clear Lake, adding 77 MWe. A second, 66-km long pipeline from Santa Rosa was



Geothermal Energy Utilization. Figure 9
Binary power or organic Rankin cycle plant using a low-temperature geothermal resource and a secondary fluid of a low boiling point (typically a hydrocarbon)

placed on line in 2004, injecting 480 l/s that are projected to add another 100 MWe to The Geyser's capacity. Table 4 lists the leading countries producing electric power.

One of the more significant aspects of geothermal power development is the size of its contribution to national and regional capacity and production of countries. The following countries or regions (Table 5) lead in this contribution with more than 5% of the electrical energy supplied by geothermal power based in data from country update papers from WGC2010 [12].

Direct Utilization

Direct use of geothermal resources is primarily for direct heat and cooling. The main utilization categories are: (1) swimming, bathing, and balneology; (2) space heating and cooling including district energy systems; (3) agricultural applications such as greenhouse and soil heating; (4) aquaculture application such as pond and raceway water heating; (5) industrial applications such as mineral extraction, food, and grain drying; and (6) geothermal (ground-source) heat pumps, used for both heating and cooling. Direct use of geothermal resources normally uses temperatures below 150°C as illustrated in Fig. 10. The main advantage of using geothermal energy for direct-use projects in this low- to intermediate-temperature range is that these resources are more widespread and exist in at least 80 countries at economic drilling depths. In addition, there are no conversion efficiency losses and projects can use conventional water-well drilling and off-the-shelf heating and cooling equipment (allowing for the temperature and chemistry of the fluid). Most projects can be on line in less than a year. Projects can be on a small scale ("mom and pop operations") such as for an individual home, single greenhouse, or aquaculture pond, but can also be a large-scale operation such as for district heating/cooling, for food and lumber drying, and mineral ore extraction.

It is often necessary to isolate the geothermal fluid from the user side to prevent corrosion and scaling. Care must be taken to prevent oxygen from entering the system (geothermal water normally is oxygen free), and dissolved gases and minerals such a boron, arsenic, and hydrogen sulfide must be removed or isolated as they are harmful to plants and animals.

Geothermal Energy Utilization. Table 4 Leading countries in electric power generation (>100 MWe) [12]

Country	Installed capacity (MWe)	Running capacity[a] (MWe)	Annual energy produced (GWh/year)	Running capacity factor	Number of units operating
United States	3,093	2,024	16,603	0.94	209
Philippines	1,904	1,774	10,311	0.66	56
Indonesia	1,197	1,197	9,600	0.92	22
Mexico	958	958	7,047	0.84	37
Italy	843	843	5,520	0.75	33
New Zealand	628	628	4,055	0.74	43
Iceland	575	575	4,597	0.91	25
Japan	536	422	3,064	0.83	20
El Salvador	204	192	1,422	0.85	7
Kenya	167	167	1,430	0.98	10
Costa Rica	166	166	1,131	0.78	6

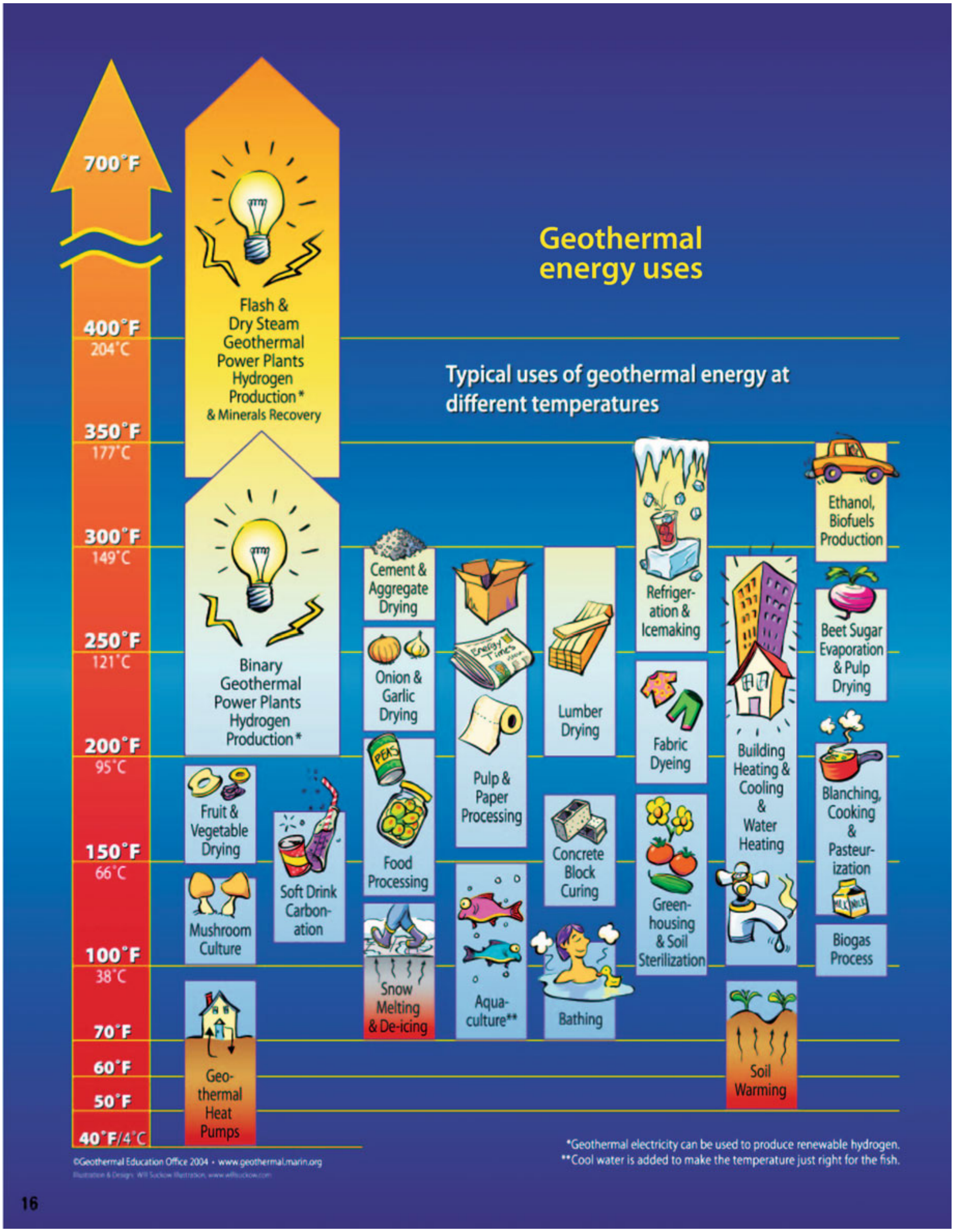
[a]Note: Some running capacity figures were not available, and thus were assumed equal to the installed capacity

Geothermal Energy Utilization. Table 5 National and regional geothermal power contributions

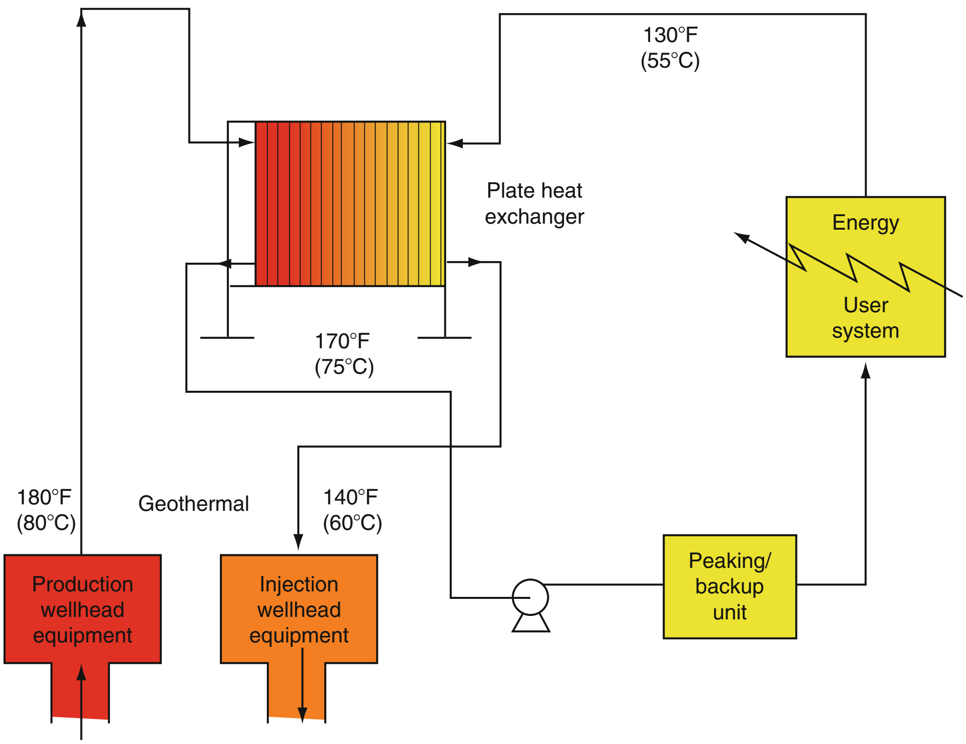
Country or region	% of national or regional capacity (MWe)	% of national or regional energy (GWh/year)
Lihir Island, Papua New Guinea	75	n/a
Tibet	30	30
San Miguel Island, Azores	25	n/a
Tuscany, Italy	25	25
Iceland	22	27
El Salvador	15	26
Kenya	12	17
Philippines	12	17
Nicaragua	11	10
Guadeloupe (Caribbean)	9	9
Costa Rica	8	12
New Zealand	6	10

On the other hand carbon dioxide, which often occurs in geothermal water, can be extracted and used for carbonated beverages or to enhance growth in greenhouses. The typical equipment for a direct-use system is illustrated in Fig. 11, and includes downhole and circulation pumps, heat exchangers (normally the plate type), transmission and distribution lines (normally insulated pipes), heat extraction equipment, peaking or back-up plants (usually fossil fuel fired) to reduce the use of geothermal fluids and reduce the number of wells required, and fluid disposal systems (injection wells). Geothermal energy can usually meet 80 to 90% of the annual heating or cooling demand, yet only sized for 50% of the peak load. Geothermal heat pumps include both open (using groundwater or lake water) and closed-loop (either in horizontal or vertical configuration) systems as illustrated in Fig. 12.

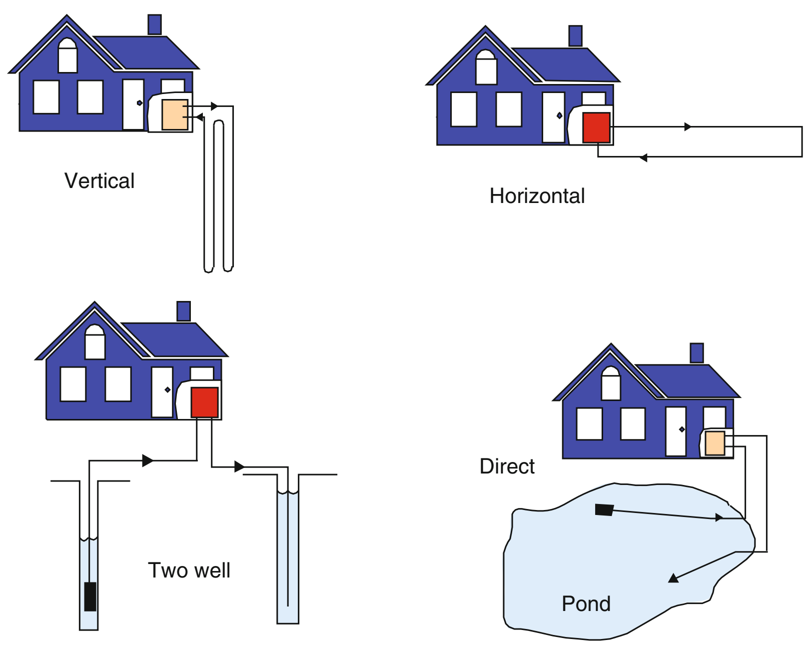
The world direct utilization of geothermal energy is difficult to determine; as, there are many diverse uses of the energy and these are sometimes small and located in remote areas. Finding someone, or even a group of people in a country who are knowledgeable on all the direct uses is difficult.



Geothermal Energy Utilization. Figure 10
Geothermal energy uses (Courtesy of the Geothermal Education Office)



Geothermal Energy Utilization. Figure 11
Typical direct-use geothermal heating system configuration



Geothermal Energy Utilization. Figure 12
Examples of common geothermal heat pump installations

In addition, even if the use can be determined, the flow rates and temperatures are usually not known or reported; thus, the capacity and energy use can only be estimated. This is especially true of geothermal waters used for swimming pools, bathing, and balneology.

One of the significant changes for WGC2010 was the increase in the number of countries reporting use. Six countries were added to the list in the current report as compared to 2005. In addition, the author is aware of three countries (Malaysia, Mozambique, and Zambia) that have geothermal direct uses, but did not provide a report for WGC2010. Thus, there are at least 81 countries with some form of direct utilization of geothermal energy.

Another significant change from 2005 is the large increase in geothermal (ground-source) heat pump installations. They increased by 229% (18% annual growth) in capacity and 245% (20% annual growth) in annual energy produced over the 5-year period to the year 2010. At present (2010), they are the largest portion of the installed capacity (69.7%) and 49.0% of the annual energy use. The equivalent number of 12-kWt units installed (the average size) is approximately 3,000,000 in 43 countries, mostly in the United States, Canada, China, and Europe; however, the data are incomplete. The equivalent number of full-load heating operating hours per year varies from 2,000 in the United States, to over 6,000 in Sweden and Finland, with a worldwide average of 2,200 full-load h/year [10].

A summary of direct-use installed capacity and annual energy use are as follows (excluding geothermal heat pumps at 69.7% and 49.0% respectively of the total); bathing/swimming/spas 43.6% and 48.8%, space heating (including district heating) 35.1% and 28.2%; greenhouse heating 10.1% and 10.4%; aquaculture 4.3% and 5.2%; industrial 3.5% and 5.3%; agricultural drying 0.8% and 0.7%; cooling and snow melting 2.4% and 1.0%; and others 0.2% and 0.4%. District heating is approximately 85% of the space-heating use [10].

In terms of the contribution of geothermal direct use to the national energy budget, two countries stand out: Iceland and Turkey. In Iceland, it provides 89% of the country's space-heating needs, which is important since heating is required almost all year and saves about $100 million in imported oil. Turkey has increased their installed capacity over the past 5 years from 1,495 to 2,084 MWt, most for district heating systems. A summary of some of the significant geothermal direct-use contributions to various countries is shown in Table 6, and the top direct-use countries are listed in Table 7 [10].

Geothermal Energy Utilization. Table 6 National geothermal direct-use contributions

Iceland: provides 89% of country's space-heating needs
Turkey: space heating has increased 40% in the past 5 years, supplying 201,000 equivalent residences and 30% of the country will be heated with geothermal in the future
Tunisia: greenhouse heating has increased from 100 to 194 ha over the past 5 years
Japan: over 2,000 hot spring resorts (onsens), over 5,000 public bath houses, and over 15,000 hotels visited by 15 million quests per years, use natural hot springs
Switzerland: has installed 60,000 geothermal heat pumps = 1/km^2, and 2,000 km of boreholes were drilled in 2009. Drain water from tunnel are used to heat nearby villages and they have also developed several geothermal projects to melt snow and ice on roads
United States: has installed 1,000,000 geothermal heat pump units, mainly in the Midwestern and eastern states, with a 12.5% annual growth. Installation of these units is around 100,000–120,000/year

Environmental Considerations

Geothermal energy is considered a renewable and "green" energy resource; however, there are several environmental impacts that must be considered and are usually mitigated. These are emission of harmful gases, noise pollution, water use and quality, land use, and impact on natural phenomena, wildlife, and vegetation [13].

Emissions: These are usually associated with steam power plant cooling towers that produce water vapor emission (steam), not smoke. The potential gases that can be released, depending upon the reservoir type are carbon dioxide, sulfur dioxide, nitrous oxides, hydrogen sulfide, along with particulate matter. A coal-fired power plant produces the following kilograms of emissions per MWh as compared to a geothermal power

Geothermal Energy Utilization. Table 7 Top Direct-Use Countries

Country	GWh/ year	MWt	Main applications
China	20,932	8,898	Bathing/district heating
United States	15,710	12,611	GHP
Sweden	12,585	4,460	GHP
Turkey	10,247	2,084	District heating
Japan	7,139	2,100	Bathing (onsens)
Iceland	6,768	1,826	District heating
France	3,592	1,345	District heating
Germany	3,546	2,485	Bathing/district heating
Netherlands	2,972	1,410	GHP
Italy	2,762	867	Spas/space heating
Hungary	2,713	655	Spas/greenhouses
New Zealand	2,654	393	Industrial uses
Canada	2,465	1,126	GHP
Switzerland	2,143	1,061	GHP

plant: 994 vs. up to 40 for carbon dioxide, 4.71 vs. up to 0.16 for sulfur dioxide, 1.95 vs. 0 for nitrogen oxides, 0 vs. 0.08 for hydrogen sulfide (H_2S), and 1.01 vs. 0 for particulate matter. Hydrogen sulfide is routinely treated at geothermal power plants, and converted to elemental sulfur. In comparison, oil-fired power plants produce 814 kg and natural gas fired plants 550 kg of H_2S/MWh. Binary power plants and direct-use projects normally do not produce any pollutants, as the water is injected back into the ground after use without exposing it to the atmosphere.

Noise: The majority of the noise produced at a power plant or direct-use site is during the well-drilling operation, which can shut down at night. The noise from a power plant is not considered an issue of concern, as it is extremely low, unless you are next to or inside the plant. Most of the noise comes from cooling fans and the rotating turbines.

Water use: Geothermal flash steam plants use about 20 l of fresh water/MWh, while binary air-cooled plants use no fresh water, as compared to a coal plant that uses 1,370 l/MWh. Oil plant use is about 15% less and nuclear about 25% more than the coal plant (www.cleanenergy.org). The only change in the fluid during use is to cool it, and usually the fluid is returned to the same aquifer so it does not mix with the shallow groundwater. At The Geysers facility in northern California, 42 million liters of treated wastewater from Santa Rosa are pumped daily for injection into the geothermal reservoir, reducing surface water pollution in the community and increasing the production of the geothermal field. A similar project supplies waste water (29 million liters daily) from the Clear Lake area on the northeast side of the The Geysers. These projects have increased the capacity of the field by about 200 MWe.

Land use: Geothermal power plants are designed to "blend-in" with the surrounding landscape, and can be located near recreational areas with minimum land and visual impacts. They generally consist of small modular plants under 100 MWe as compared to coal or nuclear plants of around 1,000 MWe. Typically, a geothermal facility uses 404 m^2 of land/GWh compared to a coal facility that uses 3,632 m^2/GWh and a wind farm that uses 1,335 m^2/GWh. Subsidence and induced seismicity are two land use issues that must be considered when withdrawing fluids from the ground. These are usually mitigated by injecting the spent fluid back into the same reservoir. There have been problems with subsidence at the Wairakei geothermal field in New Zealand; however, this has been checked by injection. Induced seismicity is also associated with EGS projects, producing earthquakes of less than 3.4 on the Richter scale. Neither of these potential problems is associated with direct-use projects, as the fluid use is small and well and pipelines are usually hidden. In addition, utilizing geothermal resources eliminates the mining, processing, and transporting required for electricity generation from fossil fuel and nuclear resources.

Impact on natural phenomena, wildlife, and vegetation: Plants are usually prevented from being located near geysers, fumaroles, and hot springs, as the extraction of fluids to run the turbines might impact these thermal manifestations. Most plants are located

Geothermal Energy Utilization. Table 8 Energy and greenhouse gas savings from geothermal energy production (electric at 35% efficiency and direct use at 70% efficiency)

	Fuel oil (10^6)		Carbon (10^6 t)			CO_2 (10^6 t)			SO_x (10^6 t)			NO_x (10^3 t)		
	Barrels	Tonnes	NG	Oil	Coal	NG	Oil	Coal	NG	Oil	Coal	NG	Oil	Coal
Electric	114	17	6	15	17	31	49	58	0	0.3	0.4	3.4	10.1	10.1
Direct use	154	23	9	23	27	46	74	88	0	0.5	0.5	4.5	13.6	13.6
Total	268	40	15	38	44	77	123	146	0	0.8	0.9	8.9	23.7	23.7

in areas with no nature surface discharges. If plants are located near these natural phenomena, the fluid extraction depth is planned from a different reservoir to prevent any impact. Designers and operators are especially sensitive about preserving manifestations considered sacred to indigenous people. Any site considered for a geothermal power plant, must be reviewed and considered for the impact on wildlife and vegetation, and if significant, provide a mitigation plan. Direct-use projects are usually small and thus have no significant impact on natural features.

In summary, the use of geothermal energy is reliable, providing base load power; is renewable; has minimum air emission and offsets the high air emissions of fossil fuel-fired plants; has minimum environmental impacts; is combustion free; and is a domestic fuel source.

Energy Savings

Using geothermal energy obviously replaces fossil fuel use and prevents the emission of greenhouse gases. If it is assumed that geothermal energy replaces electricity generation, the conversion efficiency is estimated at 0.35 (35%). These savings using geothermal energy at this efficiency level is summarized in Table 8 [14]. If the replacement energy for direct use is provided by burning the fuel directly, then about half this amount would be saved in heating systems (35% vs. 70% efficiency), as used in Table 8. Savings in the cooling mode of geothermal heat pumps is also included in the figures in Table 8. The savings in fossil fuel oil is equivalent to about 3 days (1%) of the world's consumption.

It should be noted when considering these savings, that some geothermal plants do emit limited amounts of the various pollutants; however, these are reduced to near zero where gas injection is used and eliminated where binary power is installed for electric power generation. Since most direct-use projects use only hot water and the spent fluid injected, the above pollutants are essentially eliminated.

Future Directions

Geothermal growth and development of electricity generation has increased significantly over the past 40 years approaching 11% annually in the early part of this period, and dropping to 3% annually in the last 10 years due to the low price of competing fuels. Direct use has remained fairly steady over the 40-year period at 10% growth annually. The majority of the increase has been due to geothermal heat pumps. At the start of this 40-year period, only ten countries reported electrical production and/or direct utilization from geothermal energy. By the end of this period, 78 countries reported utilizing geothermal energy. This is almost an eightfold increase in participating countries. At least another ten countries are actively exploring for geothermal resources and should be on line by 2015.

Developments in the future will include greater emphases on combined heat and power plants, especially those using lower temperature fluids down to 100°C. This low-temperature cascaded use will improve the economics and efficiency of these systems, such as shown by those installed in Germany and Austria and at Chena Hot Springs, Alaska. Also, there is increased interest in agriculture crop drying and

refrigeration in tropical climates to preserve products that might normally be wasted. Finally, the largest growth will include the installation and use of geothermal heat pumps, as they can be used anywhere in the world, as shown by the large developments in Switzerland, Sweden, Austria, Germany, China, Canada, and the United States.

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Geothermal Energy, Geology and Hydrology of

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Article Outline

Glossary

Core The central portion of the Earth that is composed of high density metallic, solid, and liquid components.

Crust The outer layer of the Earth composed of low to moderate density silicates and other minerals and within which the radioactive elements K, Rb, U, and Th are concentrated.

Direct use An application that uses the heat from a geothermal resource to accomplish heating, cooling and drying without converting thermal energy to another energy form.

Enhanced geothermal systems A deep geothermal system in which the porosity and permeability have been artificially enhanced through engineering methods to increase the mass flux of fluid that can be pumped through the reservoir.

Heat flow Strictly, the movement of thermal energy via diffusive conduction. Heat flow, as measured, is also a reflection of advective and convective transport.

Heat pump A device for transferring heat from one location to another.

Hydrology The scientific discipline that studies the flow of fluids in the crust.

Magma Molten rock that is one of the primary means for transferring heat to near-surface environments.

Mantle The interior portion of the Earth between the core and crust within which convective flow of material transfers heat to the crust.

Permeability The measurement or property of a medium that describes the ease with which a fluid will pass through the pores or fractures of the medium.

Plate tectonics The conceptual framework that provides a unifying principle describing the dynamic processes within the Earth.

Definition of the Subject

Geothermal energy is a ubiquitous renewable energy resource that is available virtually anywhere on the Earth. Surface manifestations of this energy resource are, however, diverse and irregularly distributed. The most obvious and dramatic examples of geothermal energy are volcanoes. Less dramatic but equally unambiguous are geysers, hot springs, and warm pools, all of which are striking by their seemingly endless outflow of warm water from the subsurface. More subtle indications of geothermal energy are measurements in boreholes, mines, and wells that inevitably show that the deeper one goes below the surface, the warmer is the rock. All of these examples unambiguously document that heat is present in the subsurface, and it is this energy resource that geothermal applications utilize.

Access to geothermal resources varies from place to place, reflecting a complex interplay of geological and hydrological processes that have developed over millions of years. As a result, the types of geothermal applications that can be developed also vary from place to place. If high temperature (greater than ~150°C) water can be accessed at depths of a few kilometers, the potential exists for installing a geothermal power plant. Lower temperature waters can be utilized for a broad range of so-called direct-use applications, whereby the thermal energy of the fluid is used for such things as drying

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timber, drying fruits and vegetables, curing concrete blocks, processing food, or heating buildings. And, virtually anywhere on the planet, at depths of a few meters to a few tens of meters, the constant flow of heat from the Earth's interior provides consistent conditions suitable for the installation of ground source heat pumps for heating and cooling. Evaluating the characteristics and magnitude of a geothermal resource requires unifying information, models, and concepts from a range of disciplines that focus on elucidating the properties of geological systems.

Introduction

Natural hot springs, volcanoes, and geysers are obvious indications that the interior of the Earth is hot. Catastrophic eruptions such as that of Mt. Vesuvius in AD 79 that destroyed the city of Pompeii and of Krakatoa in 1883 that affected weather patterns globally provide compelling evidence that the magnitude of the heat energy is huge. But, the irregular distribution of volcanoes and hot springs over the Earth's surface seems, at first glance, to be enigmatic. If the interior of the Earth is hot, why are some manifestations of that heat restricted to certain regions? What controls the distribution pattern? How large is the resource?

Answers to these questions derive from the evolution of geological processes.

Heat Sources in the Earth

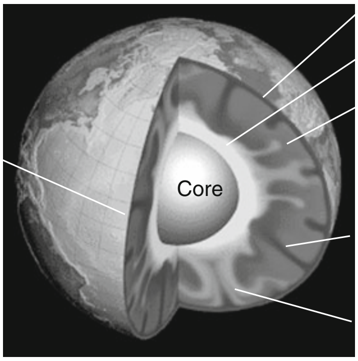
Human awareness of geothermal energy dates back thousands of years [1] although the first uses of geothermal waters remain unknown. However, it was not until the Industrial and Scientific Revolutions in the 1700s and 1800s that investigations of the interior of the Earth began. Mining activities made it apparent that as one went deeper in the Earth temperatures increased [2, 3]. Why that should be so, and how hot the interior of the Earth was remained unknown until the advent of several scientific disciplines that, together, provided an answer to these questions.

The discovery of radioactivity in the late 1890s and early 1900s provided a solution to at least part of the problem. It was eventually recognized that radioactive decay generates heat. The Earth contains a number of radioactive elements, among them potassium (K), rubidium (Rb), uranium (U), and thorium (Th), all of which release heat when radioactive decay occurs. However, it was apparent that these elements could not account for the presence of a hot interior Earth in which there existed a liquid core, a fact that was generally accepted by the end of the 1920s [4]. These elements are concentrated in the crust of the Earth [5], and are of very minor importance in the mantle and core, and therefore they cannot be the exclusive source for the heat that is observed at the surface. This conundrum was resolved when the early accretionary history of the Earth became better understood.

The Earth accreted from the solar nebula about 4.56 billion years ago [6, 7]. The materials that formed the Earth included rocky and metallic bodies as well as icy material from comets. The kinetic energy carried by these bodies when they impacted the forming planet was sufficient to heat the Earth substantially. At the same time, during the early life of the solar nebula an abundance of short-lived isotopes were also accumulating in the Earth. Particularly important were specific isotopes of aluminum, hafnium, and manganese (^{26}Al, ^{182}Hf, and ^{53}Mn, respectively). The combination of these heat-generating mechanisms ultimately resulted in the partial melting of the planet. Over a period of about 30 million years [8–13] metallic iron and related compounds became liquid and, because of their high density, settled to the core of the Earth while the remaining silicates stratified into layers (Fig. 1) of different densities. About 40% of the heat energy that is available and used in geothermal applications comes from this early period of differentiation of the Earth [14]. The remaining 60% comes from the decay of the longer-lived isotopes of K, U, Rb, and Th that have concentrated in the crust [15].

Plate Tectonics as the Physical Framework

The materials that make up the Earth are relatively poor thermal conductors. As a result, the heat deep in the Earth is conducted to the surface relatively slowly. The average heat flow at the surface of the Earth is 87 milli-Joules/m^2/s. Since a Watt (W) is



Geothermal Energy, Geology and Hydrology of. Figure 1

A cross section of the Earth showing the main structural divisions. The core, lower mantle, upper mantle, and crust are indicated. Also shown are ascending and descending limbs of convection cells (Source: US Geological Survey, http://geomag.usgs.gov/about.php)

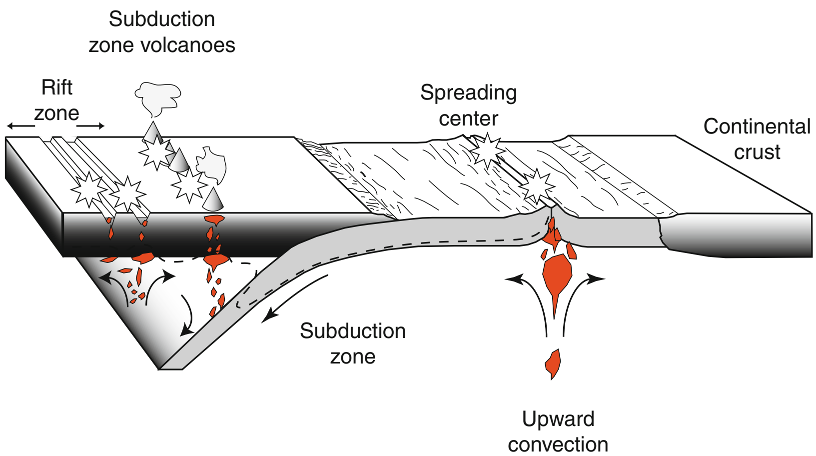
a Joule per second (J/s), this heat flow is equivalent to 87 mW/m^2. Deeper in the Earth, near the core–mantle boundary, temperatures are in excess of 3,600°C [16]. The high temperatures in the low thermal conductivity materials that compose the mantle inevitably result in a situation where the lower mantle heats sufficiently to become less dense than the immediately overlying, cooler mantle. This is a gravitationally unstable configuration, and leads to upward flow of the hotter, less dense material. As a result, conditions favorable for development of a convection system become established [17]. The consequence of this condition, over time, is that hot mantle material begins to flow upward toward the Earth's surface [18]. When this ascending mantle material approaches the surface it spreads laterally, eventually descending to complete the pattern characteristic of convection. It is through this mechanism of convection that plate tectonics is driven, providing the resource for geothermal energy.

Plate tectonics describes the features and properties of the global convection system [19, 20]. The surface of the Earth is composed of seven major plates and approximately an equal number of smaller plates. The interior regions of the plates are relatively inactive, forming stable geological environments in which there is little seismic, tectonic, or volcanic activity. The edges of the plates, however, are the regions where seismic and tectonic activity are concentrated. It is mainly in these plate-edge settings where readily accessible, geothermally interesting resources occur. There are, in addition, several other geothermally important geological settings, most notably hot spots, that figure prominently in geothermal efforts. These tectonic environments localize heat in specific ways, providing an explanation for the observation that geothermal regions appear to be constrained to specific regions and zones around the world. Each of these settings is discussed in the following sections. The exceptions to this generalization are "geopressured" resources and "Enhanced Geothermal Systems" (EGS) which are briefly discussed at the end of this chapter and are presented in detail in "► Engineered Geothermal Systems, Development and Sustainability of."

Spreading Centers

When upward ascending limbs of convection cells approach the surface of the Earth, the hot material they are carrying begins to melt as the pressure drops. The melt aggregates into magma bodies that buoyantly rise. When the ascending limb is within about 100 km of the surface it begins to spread laterally, causing the plates on either side of this zone to move away from each other (Fig. 2). Magma in the ascending limb invades this zone, forming new crust at the edges of the diverging plates. Because of these magma bodies, spreading centers have the highest heat flow of any place on the Earth's surface. Theoretically, these zones could have heat flow values approaching 1,000 mW/m^2 [14].

Although of considerable theoretical interest from a geothermal energy perspective, spreading centers are of limited practical value since they are usually found in ocean basins at several kilometers depth and far from population centers. Exceptions to this are the Imperial Valley of California and the East African Rift. Both of these settings are geothermally active. Development of geothermal resources in Africa is underway. Geothermal power production in the Imperial Valley of California, which is currently approximately 2,000 MW [21], provides a significant amount of the renewable energy generated by the state of California.



Geothermal Energy, Geology and Hydrology of. Figure 2
Schematic diagram of the main elements in plate tectonic. The *stars* indicate regions where geothermal resources are concentrated. The *dashed line* schematically indicates the general form of isotherms. Magma bodies are indicated by the *red* forms

Subduction Zones

Once crust is formed, it is conveyed away from spreading centers and slowly cools. Since most newly formed crust forms in ocean basins, it interacts with seawater as it migrates away from the spreading centers and ages. This interaction with the seawater results in the formation of mineral phases that commonly contain some water in their structure.

As required by the law of conservation of mass, convecting systems invariable have descending limbs that counter the mass flow from ascending limbs. These zones in plate tectonics are called subduction zones (Fig. 2). Subduction zones are regions where the cooled crust descends back into the mantle. Because they are colder, they have low heat flow where the initial descent into the mantle occurs. In addition, as shown in Fig. 2, isotherms within the mantle are depressed in the immediate vicinity of the descending slab of cooler material.

Nevertheless, the descending crust does heat up as it enters the mantle. As the crust heats, it eventually reaches temperatures sufficient to cause the breakdown of the hydrous minerals that formed when the crust was interacting with seawater. This breakdown of hydrous minerals liberates water. Because of its relatively low density, the released water migrates upward into the overlying warmer mantle where it causes a complex series of reactions, including partial melting. The melts that are generated ascend to the surface, where they form prominent volcanic chains. The so-called Ring of Fire that surrounds the Pacific Ocean formed precisely as a result of this process. This process is, in essence, a heat transfer mechanism whereby the rising magma brings heat to the near-surface environment from the deeper mantle.

The volcanic systems associated with subduction zones are, globally, the most common settings for geothermal power generation and direct use. Geothermal facilities that have utilized the thermal energy in these settings have been built in Chile, Central America, the Cascades in Northern California and Oregon, Japan, the Philippines, and the Mediterranean region, to name a few.

Commonly associated with the volcanic chain that forms above subduction zones are secondary rift systems, or back-arc basins (Fig. 2). These environments are extensional systems somewhat like spreading centers [22]. They appear to develop in response to complex flow dynamics in the mantle above the descending slab [23]. Because they involve the same type of ascending hot mantle flow as found in

spreading centers, magma bodies form and ascend to the near surface. As a result, these settings can also be important high temperature zones within which geothermal resources concentrate. An example of this type of environment is the Taupo volcanic zone on the North Island of New Zealand, where occurred the first large-scale development of geothermal power in the world. Although geologically more complex, the Basin and Range Province of the Western United States is, in part, a manifestation of similar processes. Existing and/or planned geothermal facilities in eastern Arizona, California, Colorado, Idaho, Montana, Nevada, and New Mexico, to name a few, utilize geothermal resources in this type of setting.

Transform Faults

The third type of plate boundary is a feature called a transform fault. Transform faults are places where plates move past each other horizontally, forming fault zones in which the rock has been crushed and fragmented. Although transform faults are not intrinsically associated with magma bodies, local geological conditions can result in high heat flow and the development of a geothermal resource. This can occur because such zones provide easy flow paths for warm or hot waters at depth to ascend to shallower levels. The San Andreas fault in California is one example of a transform fault along which warm and hot springs are common and for which there is chemical and isotopic evidence of flow from great depth [24].

Hot Spots

Hot spots are surface manifestations of a persistent heat source deep in the mantle. They are characterized by long-lived volcanic activity and by the fact that they exhibit no specific relationship with any type of plate boundary. Hot spots are found relatively commonly in the interiors of plates. Their cause remains largely unknown. Iceland and the Hawaiian Island–Emperor Seamount chain are two examples of hot spots. In the case of Iceland, the heat and magma source for the hotspot coincides with the spreading center in the Atlantic Ocean. It has persisted at that site for more than 10 million years. The Hawaiian–Emperor chain, by contrast, has traveled over a hot spot that has persisted for more than 50 million years. The only active volcano in this chain is the island of Hawaii. Both of these locations have geothermal facilities, Iceland in particular being a spectacular example of the broad use of geothermal energy resources for both space and district heating and power generation.

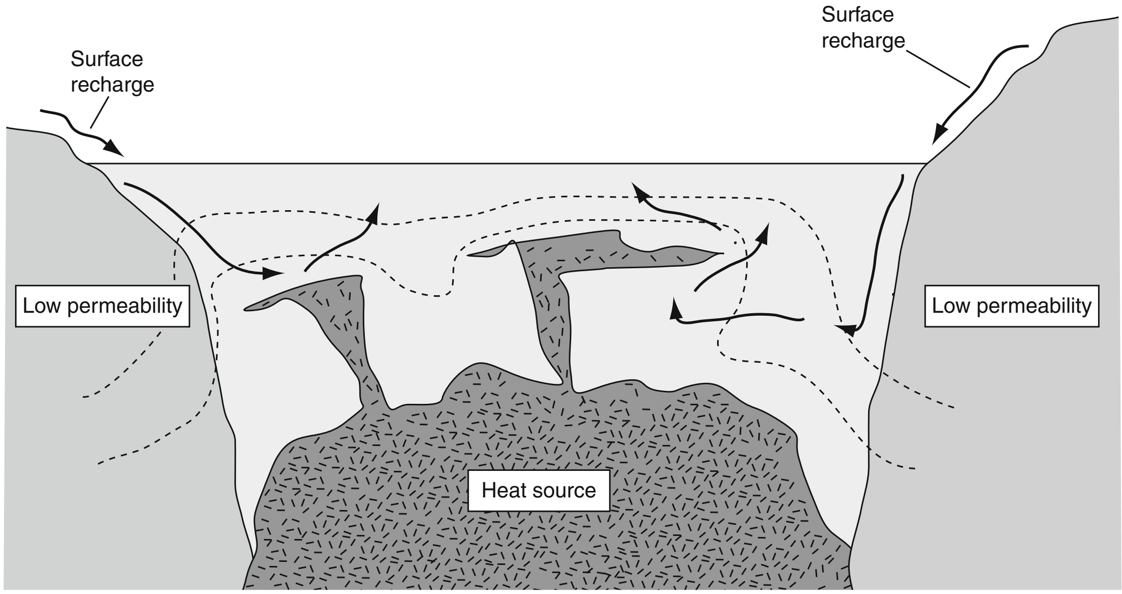
Heat and Water in the Subsurface

The above discussion provides a broad conceptual framework for understanding how geothermal heat becomes concentrated in certain regions. Generally, the responsible processes transport heat to the near surface either through the intrusion of magma or the flow of deep circulating water. The following discussion considers in more detail the specific geological and hydrological conditions that make a heat resource useful for geothermal applications.

Heat Sources

Geothermal power generation uses the heat energy of moderate to high temperature (>140°C) geothermal fluids to power turbines that drive electrical generators (see "► Geothermal Power Conversion Technology"). Direct-use applications, such as aquaculture, food drying, district heating systems, and greenhouses, among others, rely on lower temperature (less than about 150°C) geothermal fluids to directly heat an environment for specific purposes. Regardless of the technology employed, there are several basic geological and hydrological conditions that determine whether a resource is suitable for its intended use. The key requirements are an adequate resource that can provide the requisite thermal energy for the specific application and whether there is an adequate fluid flow to transfer the thermal energy to power the engineered system.

Cooling magma bodies, or their hot solidified counterparts, are the heat source for many geothermal applications. These bodies can be of many forms and sizes. Shown in Fig. 3 is an example of the kind of irregularity they may have. The main magma body (pluton) can be a few hundred meters to kilometers in size, with offshoots (dikes and sills) a few meters

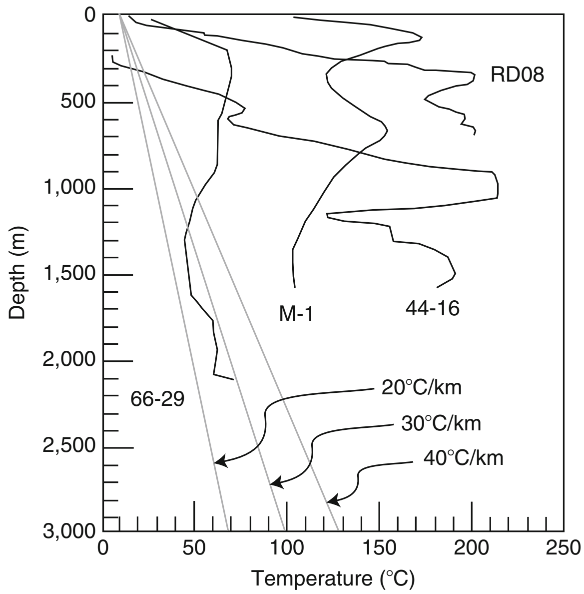


Geothermal Energy, Geology and Hydrology of. Figure 3
Schematic diagram of a high temperature geothermal system. The *arrows* indicate the flow path of water in the subsurface. Hypothetical 250°C and 300°C isotherms are indicated by the *dashed lines*. The *dark gray* body labeled "Heat source" represents a cooling igneous body that once was a magma chamber. The *light gray* pattern indicates porous and permeable rocks into which the magma intruded. The *medium gray* rocks labeled "Low permeability" indicate highland regions that provide recharge of water to the subsurface

to many tens of meters in size. The magma, when it is liquid, will have temperatures between about 700°C and 1,100°C, depending on its composition. The cooling rate for shallow plutons is tens to hundreds of degrees per million years; hence, the lifetime of useful heat output can be quite long. This allows geothermal development of intrusive bodies that are several to ten million years old, depending on the local conditions.

The distribution of heat around these bodies can result in complex isotherm patterns. Shown in Fig. 3 are hypothetical 300°C and 250°C isotherms that might be expected solely from slow cooling of the heat source. The form of the isotherms is influenced by the geometry of the igneous body, as well as the local geology. As will be discussed below, another important factor that influences isotherm form is the extent to which fluid flow transfers heat away from the region. Regardless of the underlying mechanism, the isotherms in such a setting are likely to have an irregular form. It is for this reason that temperature gradient holes are used in exploration efforts to determine the real vs hypothetical subsurface temperature distribution [25]. The importance of acquiring such information is shown in Fig. 4, which depicts measured temperatures in the subsurface in Long Valley caldera in the eastern Sierra Nevada mountains [26]. The Long Valley caldera is a region of geothermal activity and is the site of a 37 MW power generation facility. Linear geothermal gradients are shown for comparison. Note the pronounced departure from linearity. The prominent temperature spikes, as well as the complex variations in temperature over distances of several hundred meters reflect the effects of fluid flow.

The other main source of useful geothermal energy is deep circulation of water in natural aquifer systems. In this instance, meteoric water flows into the subsurface, often along faults or other flow paths. The situation is exactly analogous to the flow



Geothermal Energy, Geology and Hydrology of. Figure 4

Measured temperature profiles in bore holes at Long Valley caldera, California (Data from [26])

field depicted on the right hand side of Fig. 3, except in this case there is no specific heat source present. Instead, the descending water flows to depths of several kilometers where the normal geothermal gradient (10–30°C/km) results in the circulating fluid coming in to contact with rocks in the temperature range of 50–100°C. Deep fault zones that intersect these naturally circulating fluids can allow rapid ascent of the fluid from depth, resulting in the development of warm or hot springs. Although such fluids do not possess sufficient energy to support power generation, they do have sufficient thermal energy for successful development of direct-use applications.

Whether or not a high temperature zone will be useful for geothermal applications depends on whether the heat it possesses can be brought to the surface in sufficient quantity. The fundamental requirement for achieving this is the ability to circulate fluid in sufficient volume to bring the heat to the surface at a rate that matches the demand of the application. The material property that determines whether this criteria can be met is the permeability.

Subsurface Fluid Flow: Porosity and Permeability

Rocks are generally classified as igneous, metamorphic, or sedimentary, depending upon the principal process that controlled their formation. Igneous rocks crystallized from magmas and usually have a very low percentage (usually much less than 10%) of their volume occupied by pore space (*porosity*). Sedimentary rocks form as the products of erosion and deposition, often in response to the effects of water movement or settling in sedimentary basins. Such rocks have a wide range of porosities, but can be quite porous, with values easily reaching 40% or more. Metamorphic rocks form as a result of changes in temperature and pressure due to burial or other physical effects. As the physical conditions evolve a rock will recrystallize, changing its mineralogy and internal structure. The porosity of metamorphic rocks usually falls somewhere between that of igneous and sedimentary rocks.

All rocks have two related but independent physical properties. One of these properties is porosity (as described above), the other is permeability. Regardless of how solid a rock appears, there will always be some amount of space between mineral grains and/or some cracks and fractures. If the pore space occurs primarily as voids between grains, the porosity is classified *as matrix-dominated porosity*. If most of the void space occurs as fractures, it is termed *fracture-dominated porosity*. The open space between mineral grains can be as small as a micron (i.e., 1 millionth of a meter) or as large as a significant fraction of a centimeter. Fractures can have similar dimensions. Measured values of rock porosity vary from a small fraction of a percent in unfractured crystalline rocks such as granites or some metamorphic rocks, to greater than 40% in some sedimentary sandstones. The porosity determines the instantaneous volume of fluid a rock can possess.

The porosity has an important effect on the thermal and mechanical properties of a rock in the subsurface. The thermal properties of water and minerals are significantly different. At 25°C, for example, the amount of energy it takes to raise the temperature of 1 kg of water 1°C is 4,180 J. On the other hand, it only takes 660 J of energy to raise the temperature of 1 kg of potassium feldspar,

a common mineral in granite, 1°C. In other words, the heat capacity of water is quite high compared to the heat capacity of many minerals. Thus, at a given temperature, assuming the porosity is 100% filled by liquid water (i.e., the rock is *saturated*), the heat content of a given volume of potassium feldspar with 1% porosity will be about half that for the case in which the porosity is 20%. Similar results are obtained for most other minerals. Heat capacity varies with mineral, and is a function of temperature. Hence, this specific result *qualitatively* illustrates the relationship between heat content, porosity, and water content (or saturation) for rock systems, but does not *quantitatively* represent the behavior of all rocks under these conditions. When assessing the available thermal energy in a potential geothermal resource, it is important to establish the porosity and degree of saturation of the rock composing the geothermal reservoir. A detailed discussion of resource assessment is provided in later entries in this book.

The ability of fluid to flow through a geothermal reservoir determines the rate at which heat can be extracted. The measure of the ease with which fluid flows through rock is the *permeability*. For an unfractured, porous, saturated rock, if the pores are not interconnected the fluid cannot flow through the rock and the permeability will necessarily be zero. In other words, regardless of the porosity, there would be no fluid flow in this case. For porous rock with interconnected porosity, the ability of fluid to flow will depend on the size of the connections between the pores, the complexity of the flow path (also called the *tortuosity*), the pressure gradient across the flow path, the shape of the pores, and certain physical properties of the fluid. For fractured rocks [27], the important characteristics affecting the permeability include the effective aperture of the fracture, its roughness, the number of fractures per rock volume, and their orientation, as well as the fluid properties.

The concept of permeability was formalized by Henry Darcy in the 1800s. He developed the relationship

$$q = -(\kappa/\mu) \cdot A \cdot \nabla(P)$$

where q is the flux ($m^3/m^2/s$), κ is the permeability (in units of area, m^2), A is the cross-sectional area (m^2), μ is the dynamic viscosity (kg/(m-s)), and $\nabla(P)$ is the gradient in pressure. This relationship strictly applies only to conditions of slow flow in porous media for a single phase [28, 29]. It is often used in more complex situations, but its limitations need to be understood. It is especially important to recognize this limitation in geothermal systems where high flow rates are often encountered. Note that a standard measure of permeability is the darcy, the conversion for which is 9.869 e^{-13} m^2/darcy.

The relationship between porosity and permeability has been formalized in several ways [30], the most useful of which is the Kozeny–Carmen equation [31–33],

$$\kappa = [n^3/(1-n)^2]/(5 \cdot S_A)^2$$

In this relationship, n is the porosity and S_A is the surface area of the pore spaces per unit volume of rock. This relationship can also be written as

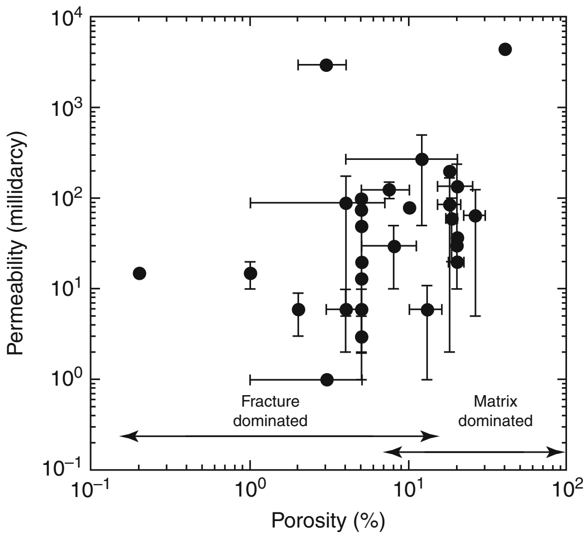
$$\kappa = c_0 \cdot T[n^3/(1-n)^2]/(S_A)^2$$

where T is the tortuosity and c_0 is a constant. The tortuosity is the ratio between the straight path between two points and the actual path length a particle would follow in the flow field. Commonly $c_0 T$ is treated as equivalent to 0.2, making it identical to the Kozeny–Carmen equation.

The ability to obtain sufficient energy for use in geothermal applications usually requires flow rates on the order of several cubic meters per second. Hence, it is important that drilling programs target regions in the subsurface with at least moderate permeability.

Permeability in Geothermal Systems

The physical properties of rocks in real geothermal systems are highly variable. Some geothermal systems extract energy from highly porous sandstones and other sedimentary rocks, while others utilize geothermal resources that occur in fractured crystalline rocks. Björnsson and Bodvarsson [34] compiled porosity and permeability data from operating geothermal power plant locations in various geological settings and documented the high degree of variability such systems possess (Fig. 5). Despite the variability, it is apparent that systems in which the porosity is



Geothermal Energy, Geology and Hydrology of. Figure 5
Observed porosity vs permeability in geothermal systems used for power generation (Data from [34])

primarily in the form of matrix pores rather than fractures, a much higher porosity is required to achieve sufficient flow to support power generation. Fracture-dominated systems, on the other hand, can have very low overall porosity and permeability yet support sufficient flow to generate power. This observation suggests that in a fractured rock mass, fluid flow may be concentrated in a very small proportion of the overall fracture population [27] and yet still be adequate for supporting power generation. This conclusion is supported by modeling that has recently been reported [35].

Using a fractal model for fracture properties, along with data from well-characterized geothermal systems, Williams [35] demonstrated that the bulk of fluid flow in these geothermal systems occurs in a small fraction of the total porosity. This implies that a few fractures out of a population of many fractures carry most of the fluid flow. These results emphasize the importance of sufficiently characterizing rock properties at a site to establish the likely range of permeability properties. Once established, this information can be used to determine drilling targets and likely production levels.

Future Directions

Basic Geological Principles for Enhanced Geothermal Systems (EGS)

Implicit in the discussion of the driving forces for plate tectonics is the fact that heat is present everywhere in the subsurface. Geothermal gradients of a few degrees to several tens of degrees per kilometer lead to the conclusion that temperatures greater than 300°C, which are sufficient to generate power, can be obtained at depths between 5 and 15 km virtually anywhere in the world. Pursuit of this resource has a long history [36–38]. Indeed, a recent study [39] concluded that in the United States alone, the amount of thermal energy that could be accessed at depths of less than 10 km is in excess of 13 million exajoules (1 exajoule = 10^{18} J). If only 1.5% of that energy could be accessed it would supply more than 2,000 times the annual electrical power generation needs of the country. Similar conclusions apply for almost every country on the planet.

The challenges faced in accessing this energy are the depths to which drilling must routinely go to tap the resource, and the ability to bring the heat to the surface. The depth to be drilled is determined by the regional geological framework. The interiors of plates often are stable environments that have had little magmatic activity. In the absence of magmatic activity, normal geothermal gradients in the interiors of plates are relatively low, on the order of a few degrees per kilometer to about 20°/km. These conditions would require drilling to depths that approach the limits of current drilling technology. Nevertheless, all plates have large areas in which adequate temperatures can be accessed at depths less than 10 km, and represent potential drilling targets for EGS systems.

The other challenge faced by EGS development is the ability to circulate fluids to depths in sufficient volumes to extract useful quantities of heat. Deep boreholes tend to enter regions where the permeability is low and the volume of subsurface water is small. To overcome these problems, it is possible to enhance the permeability of the rock using standard techniques of hydrofracturing that have been practiced in the oil and gas industry for decades. Hydrofracturing allows development of

sufficient fracture permeability to support fluid flow at the volumes required for power generation. For a detailed discussion of EGS technology, see "► Engineered Geothermal Systems, Development and Sustainability of."

Basic Geological Principles for Non-power Producing Applications

Direct-use applications and ground source heat pumps require much lower temperatures than those needed for power generation [40]. As a result, they can usually rely on resources that are in the relatively shallow subsurface. Direct-use applications, such as aquaculture, spas, food processing, lumber drying, etc., often are located where warm or hot water occurs naturally in springs or the immediate subsurface. Such settings mainly rely on high permeability zones, such as local faults or porous and fractured rocks such as some volcanic deposits, for the fluid supply. As a result, most such applications are located in regions where recent volcanic activity has provided a thermal resource.

The use of ground source heat pumps for space heating and cooling [41], on the other hand, is not restricted by location. Ground source heat pumps utilize technology similar to that employed to cool the interior of refrigerators. Using technologically sophisticated but mechanically simple heat pumps, these systems can extract heat from the subsurface and transfer it to a building space (for space heating), or remove heat from a building space and deposit it in the subsurface (for cooling). Because of their high efficiencies, these heat pumps require a thermal resource of only 10–15°C (ca. 50–60°F). Such temperatures are readily accessed within 30–100 m in the subsurface, due to the normal geothermal gradient. These systems can be installed in virtually any geological setting. However, their long-term performance is influenced by the thermal properties of the rock types in a given area, as well as the presence or absence of subsurface water. If an active aquifer is located at the same site, the thermal stability of the system can be influenced by the rate of flow and recharge area of the aquifer. Shallower systems, such as trench installations, are also possible in some areas if suitable space is available and if appropriate soil depths occur.

Summary

Geothermal resources are a reflection of the underlying global and local geological and hydrological framework. The most thermally rich resources tend to concentrate in environments that have abundant volcanic activity. These tend to be controlled by plate tectonic processes and are, specifically, spreading centers, volcanic chains associated with subduction zones and hot spots. The local geological characteristics that favor useful resources include relatively shallow depths to the resource, high permeability in the rocks surrounding the resource, and adequate fluids. These conditions apply for all applications except those utilizing ground source heat pumps. For these systems, virtually any setting is suitable, since the normal flow of heat from the Earth is adequate to assure a thermal resource of a 10–20°C within a few tens to a few hundreds of meters in the subsurface.

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Geothermal Energy, Nature, Use, and Expectations

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Article Outline

Glossary

Base-load demand Continuous demand for electricity. Power generation plants with high-capacity factors combine as a practical source of continuous base-load supplies.

Capacity factor The energy generated in a span of time divided by the maximum energy that could have been generated at full (name plate) power of the plant during that period of time, most often expressed as a percentage of 1 year of plant operation. The maximum amount of power a plant can generate is its name plate capacity.

Conduction-dominated systems Earth systems of heat transfer in which heat flow is principally via the contact of rocks (and pore- and fracture-filling fluids and gasses in rocks) with a capacity to transfer thermal energy from higher to lower temperature conditions. Non-volcanic (amagmatic) geothermal systems tend to become conduction-dominated systems.

Convection-dominated systems Earth systems of heat transfer in which heat flow is principally via flow of gasses, fluids, and molten rock (magma) from higher to lower temperature conditions. Volcanic geothermal systems tend to become convection-dominated systems.

Dispatchable electricity Power generation systems that can quickly shift from nil to full generation capacity and balance electricity supply and demand within safe technical limits of transmission grids.

Engineered (or enhanced) geothermal systems (EGS) Geothermal reservoirs in which technologies enable economic utilization of low permeability conductive dry rocks or low productivity convective water-bearing systems by creating fluid connectivity through hydraulic, thermal, or chemical stimulation methods or advanced well configurations. EGS also refer to activities to increase the permeability in a targeted subsurface volume via injecting and withdrawing fluids into and from the rock formations that are intended to increase the ability to extract energy from a subsurface heat source.

Geothermal energy Accessible thermal energy stored in the Earth's interior, in rock, gasses, and fluids usable for the generation of electricity and to supply heat for direct use. Continuous radiation from the natural decay of elements and residual energy from the earth's formation are the main sources of geothermal energy.

Ground source heat pumps Equipment that circulates fluids or gasses from lower to higher

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temperature conditions, or the reverse to heat or cool buildings or industrial processes. Ground source heat pumps (GSHPs) are most commonly used to heat in winter and cool in summer.

Hot sedimentary aquifers Any geologic reservoir that has a capacity to flow fluids at a rate and a temperature sufficient to meet a market for power generation and the direct use of thermal energy. The most accessible and the most prospective hot sedimentary aquifers (HSA) are naturally highly permeable, are overlain by rocks that act as thermal insulators, and are underlain by an effective source of heat energy (magma or high-heat-producing rocks such as granite plutons rich in uranium).

Definition of Geothermal Energy

Geothermal energy is the terrestrial generated heat stored in, or discharged from rocks and fluids (water, brines, gasses) saturated pore space, fractures, and cavities and is widely harnessed in two ways: for power (electricity) generation and for direct use, e.g., heating, cooling, aquaculture, horticulture, spas, and a variety of industrial processes, including drying. Thermal energy is used by taking heat from geothermal reservoirs replenished by natural recharge. Reservoirs that are naturally sufficiently hot and permeable are called hydrothermal reservoirs, whereas reservoirs that are sufficiently hot but require artificial improvement of a rock permeability are called engineered (enhanced) geothermal systems (EGS). Geothermal energy can be used to generate electricity or directly for processes that need thermal energy. Geothermal energy can be used to provide dispatchable, base-load electricity power plants.

Introduction

Geothermal energy systems have a modest environmental footprint, will not be impacted by climate change, and have potential to become the world's lowest cost source of sustainable thermal fuel for zero emission, base-load direct use, and power generation. Displacement of more emissive fossil energy supplies with geothermal energy can also be expected to play a key role in climate change mitigation strategies.

The use of energy extracted from temperatures of the Earth at shallow depth by means of ground source heat pumps (GSHP) is a common form of geothermal energy use. The direct uses of natural flows of geothermally heated waters to surface have been practiced at least since the Middle Paleolithic [1], and industrial utilization began in Italy by exploiting boric acid from the geothermal zone of Larderello, where in 1904 the first kilowatts of electric energy (kWe) were generated and in 1913 the first 250-kWe commercial geothermal power plant was installed [2].

Where very high-temperature fluids (>180°C) flow naturally to surface (e.g., where heat transfer by convection dominates), geothermal resources are the manifestation of two factors:

- A geologic heat source to replenish thermal energy outflow
- A hydrothermal reservoir that can be tapped to produce geothermal fluids for its direct use and/or for generating electricity

Elsewhere, a third geologic factor, the insulating capacity of rocks (acting as a thermal blanket) is an additional necessary natural ingredient in the process of accumulating usable, stored heat energy in geologic reservoirs that can be tapped to flow heat energy and replenished by convective and conductive *heat flow* from sources of geothermal energy.

Usable geothermal systems occur in a variety of geological settings. These are frequently categorized as follows:

1. High-temperature (>180°C) systems at depths above (approximately) 3.5 km are generally associated with recent volcanic activity and mantle hot spot anomalies. Other high-temperature geothermal systems below (approximately) 3.5 km are associated with anomalously high-heat-producing crustal rocks, mostly granites.
2. Intermediate-temperature systems (100–180°C).
3. Low-temperature (<100°C) systems.

Both intermediate- and low-temperature systems are also found in continental settings, formed by above normal heat production through radioactive isotope decay; they include aquifers charged by water heated through circulation along deeply penetrating fault zones. However, there are several notable exceptions to these temperature-defined categories, and under appropriate conditions, high-, intermediate-, and low-temperature geothermal fields can be utilized for both

power generation and the direct use of heat. Offshore geothermal resources are also sometimes included in lists of ocean energy systems [3].

Geothermal systems can also be classified as: *convection-dominated systems*, which include liquid-and vapor-dominated hydrothermal systems; *conduction-dominated systems* which include hot rocks; and *hybrid systems* that are sourced from convection, conduction, and high-heat-producing source rocks. Geologic aquifers that overlie radiating sources of heat and gain heat via convection and/or conduction are sometimes called *hot sedimentary aquifer systems.*

The most widely recognized manifestations of geothermal energy are related to convective heat flow, including: hot springs and geysers (e.g., the movement of hot water to land surface); volcanoes (e.g., the movement of magma to land surface and sea floors); and certain forms of economically significant minerals deposits resulting from their recovery from the injection of geothermally heated fluids into lower temperature levels where minerals crystallize and are accumulated.

Geothermal wells produce naturally hot fluids contained in hydrothermal reservoirs from a continuous spectrum of natural high to low permeability and porosity (including natural fractures). The capacity of geothermal reservoirs to flow hot fluids can be enhanced with hydraulic fracture stimulation and chemical treatment (ex. acidization), creating artificial fluid pathways in *enhanced or engineered geothermal systems* (EGS) as well described in detail in Reference [4]. Once at surface, heated fluids can be used to generate electric energy in a thermal power plant, or used in other applications requiring heat, as heating and cooling of buildings, district heating systems, aquaculture, agriculture, balneology, industrial processes, and mineral drying. Space heating and cooling can also be achieved with GHP systems.

The number, depth, and diameter of geothermal energy production wells vary with local requirements for direct use and electricity power plants. Higher temperatures and higher flow rates result in more thermal energy production per well. Wells drilled to depths down to 3.5 km in volcanic areas frequently produce high-temperature (>180°C) fluids to surface. Indeed, temperatures above 1,000°C can occur at less than 10 km depth in areas of magma intrusion. Given the global average land area surface temperature of (about) 15°C and an approximate global geothermal gradient for land areas outside volcanic settings of (about) 30°C/km, the same high temperature (>180°C) can be reached (on average) at a depth of about 5.5 to 10 km below ground level.

Electricity Generation

The main types of geothermal power plants use direct steam (often called dry steam), flashed steam, and binary cycles.

Power plants that use dry and/or flashed steam to spin turbines are the most commonly deployed form of geothermal electricity generation. These plants use the heat energy contained in water and steam flowed from geothermal wells to spin turbines, converting thermal and kinetic energy to electrical energy.

Organic Rankine power plants employing secondary working fluids are increasingly being used for geothermal power generation. These so-called binary closed-loop power plants do not flow produced geothermal fluids directly into turbines. Thermal energy contained in water and/or steam produced from geothermal wells is transferred to a secondary working fluid using a heat exchanger (hence the term binary closed loop). Organic compounds with lower boiling points than water (such as isopentane that boils at atmospheric pressure at about 28°C) are often used as working fluids. The heat energy in the geothermal fluid boils the working fluid changing it from a liquid to a pressurized organic vapor within the closed loop, which can then be expanded in a turbine to spin a generator. The exhausted working fluid is cooled, condensed back into a liquid, pressurized, and then recycled into the heat exchanger to complete the cycle.

Direct Use

Direct use provides heating and cooling for buildings including district heating, fish ponds, greenhouses, bathing, wellness and swimming pools, water purification/desalination, and industrial and process heat for agricultural products and mineral extraction and drying.

For space heating, two basic types of systems are used: open or closed loop. Open loop (single pipe) systems utilize directly the geothermal water extracted from a well to circulate through radiators. Closed loop (double pipe) systems use heat exchangers to transfer

heat from the geothermal water to a closed loop that circulates heated freshwater through the radiators. This system is commonly used because of the chemical composition of the geothermal water. In both cases the spent geothermal water is disposed of into injection wells and a conventional backup boiler may be provided to meet peak demand.

Transmission pipelines for the direct use of geothermal energy consist mostly of steel insulated by rock wool (surface pipes) or polyurethane (subsurface). However, several small villages and farming communities have successfully used plastic pipes (polybutylene) with polyurethane insulation as transmission pipes in Iceland. It is for your consideration, as Iceland is mentioned below. The temperature drop is insignificant in large-diameter pipes with a high flow rate, as observed in Iceland where geothermal water is transported up to 63 km from the geothermal fields to towns.

It is debatable whether geothermal heat pumps (GHP), also called ground source heat pumps (GSHP), are purely an application of geothermal energy or also partially use stored solar energy. GHP technology is based on the relatively constant ground or groundwater temperature ranging from 4°C to 30°C to provide space heating, cooling, and domestic hot water for all types of buildings. Extracting energy during heating periods cools the ground locally. This effect can be minimized by dimensioning the number and depth of probes in order to avoid harmful impacts on the ground. These impacts are also reduced by storing heat underground during cooling periods in the summer months.

There are two main types of GHP systems: closed loop and open loop. In ground-coupled systems, a closed loop of plastic pipe is placed into the ground, either horizontally at 1–2 m depth or vertically in a borehole down to 50–250 m depth. A water-antifreeze solution is circulated through the pipe. Heat is collected from the ground in the winter and reinjected to the ground in the summer. An open-loop system uses groundwater or lake water directly as a heat source in a heat exchanger and then discharges it into another well or into the same water reservoir [5].

Heat pumps operate similarly to vapor-compression refrigeration units with heat rejected in the condenser for heating or extracted in the evaporator used for cooling. GHP efficiency is described by a coefficient of performance (COP) which scales the heating or cooling output to the electrical energy input. GHPs typically exhibit between three and five COP [5, 6]. The seasonal performance factor (SPF) provides a metric of the overall annual efficiency of a GHP system. It is the ratio of useful heat to the consumed driving energy (both in kilowatt hour per year), and it is slightly lower than the COP.

Comparative Advantages of Geothermal Energy Use

Geothermal energy use has several comparative advantages in competitive energy markets.

- Geothermal plants have low-emission to emission-free operations and relatively modest land footprints. The average direct emissions yield of partially open cycle, hydrothermal flash, and direct steam electric power plants yield is about 120 g CO_2/kWhe. This is the weighted average of 85% of the world's power plant capacity, according to References [7, 8]. Current binary cycle plants with total reinjection yield less than 1 g CO_2/kWhe in direct emissions. Emissions from direct use applications are even lower [9]. Over its full life cycle (including the manufacture and transport of materials and equipment), CO_2 equivalent emissions range from 23 to 80 g/kWhe for binary plants (based on References [10, 11]) and from 14 to 202 g/kWht for district heating systems and GHPs (based on Reference [12]). This means geothermal resources are environmentally advantageous and the net energy supplied more than offsets the environmental impacts of human, energy, and material inputs.
- Geothermal electric power plants have characteristically high-capacity factors; the average for power generation in 2009 is 74.5% (67,246 $GWh_{electrical}$ used from installed capacity of 10.340 $GW_{electrical}$ in December 2008 based on Reference [13]), and modern geothermal power plants exhibit capacity factors greater than 90%. This makes geothermal energy well suited for base-load (24/7), dispatchable energy use.
- The average estimated 27.5% capacity factor for direct use in 2009 (121.7 $TWh_{thermal}$ used from installed capacity of 50.6 $GW_{thermal}$ based on Reference [14]) can be improved with smart grids (as for

domestic and industrial solar energy generation) by employing combined heat and power systems, by using geothermal heat absorptive and vapor-compression cooling technology, and by expanding the distributed use of geothermal (ground source) heat pump for both heating and cooling applications, and

- Properly managed geothermal reservoir systems are sustainable for very long-term operation, comparable to or exceeding the foreseeable design life of associated surface plant and equipment.
- Displacement of more emissive fossil energy supplies with geothermal energy can also be expected to play a key role in climate change mitigation strategies.

Geothermal Resources, Reserves, and Supplies

The theoretical global geothermal resource base corresponds to the thermal energy stored in the Earth's crust (heat in place). The technical (prospective) global geothermal resource is the fraction of the earth's stored heat that is accessible and extractable for use with foreseeable technologies, without regard to economics. Technical resources can be subdivided into three categories in order of increasing geological confidence: inferred, indicated, and measured [15] with measured geothermal resources evidenced with subsurface information to demonstrate its usability. Geothermal reserves are the portion of geothermal resources that can confidently be used for economic purposes. Geothermal reserves developed and connected to markets are energy supplies and global supplies.

Geothermal Supplies

At year-end 2010, geothermal energy supplies were used to generate base-load electricity in 24 countries with an installed capacity of nearly 11 GW of electricity and a global average capacity factor of nearly 75%, with newer installations above 90%, providing 10–30% of their electricity demand in six countries [13]. Figure 1 provides the geothermal electricity generation capacity by country and the mapped (estimated) distribution of global heat flow in milliwatts per square meter (mW/m^2).

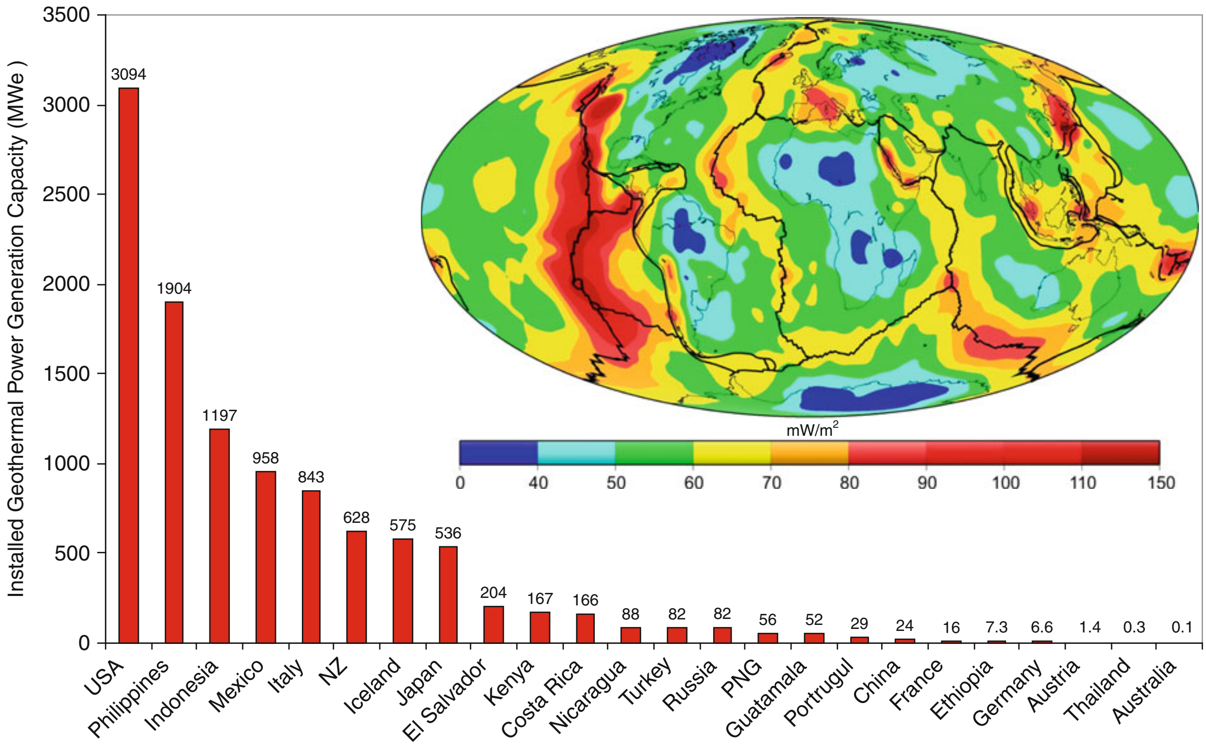
At year-end 2010, geothermal energy supplies are also used for direct use applications in 78 countries, accounting for 50 $GW_{thermal}$ including district (space) heating and cooling and geothermal (ground source) heat pumps, which have achieved significant market penetration worldwide [14]. Geothermal electric installed capacity by country in 2009. In the 40-year term 1970–2009, the average annual growth of geothermal electric installed capacity is 7% per annum; and in the 35-year term 1975–2009, the average annual growth for geothermal direct use is 11% per annum [13, 14, 17–19].

Geothermal Resources and Reserves

The total thermal energy contained in the Earth is on the order of 12.6×10^{12} EJ and that of the crust is on the order of 5.4×10^{9} EJ to depths of up to 50 km [20]. The main sources of this energy are due to the heat flow from the earth's core and mantle and that generated by the continuous decay of radioactive isotopes in the crust itself. Heat is transferred from the interior toward the surface, mostly by conduction, at an average of 0.065 W/m^2 on continents and 0.101 W/m^2 through the ocean floor. The result is a global terrestrial heat flow rate of around 1,400 EJ/year. Considering that continents cover ~30% of the earth's surface and their lower average heat flow, the terrestrial heat flow under continents has been estimated at 315 EJ/year [21].

Under continents, the stored thermal energy within 50, 10, 5, and 3 km depth (all depths reachable with the current drilling technology) has been estimated as presented as the theoretical usable geothermal energy in Fig. 2. For the Australian continent alone, Reference [24] estimated that recovery of just 1% of the stored geothermal energy above 150°C to 5 km in the Australian continental crust corresponds to 190,000 EJ. Based on these estimates, the theoretically available resource is enormous and clearly not a limiting factor for global geothermal deployment.

Geothermal energy is a renewable resource. As thermal energy is extracted from the active reservoir, it creates locally cooler regions temporarily. Geothermal projects are typically operated at production rates that cause local declines in pressure and/or in temperature over the economic lifetime of the installed facilities. These cooler and lower pressure zones in the reservoir lead to gradients that result in continuous recharge by conduction from hotter rock and convection and advection of fluid from



Geothermal Energy, Nature, Use, and Expectations. Figure 1
Geothermal electric installed capacity by country in 2009. This figure also depicts global average heat flow in milliwatts per square meter and tectonic plate boundaries (*black lines*) (Illustration adapted from a figure in Reference [16] with data from Reference [13]). This map of heat flow does not reconcile all geothermal information. The delineation of geothermal resources will be improved by integrating temperature gradient, heat flow, and reservoir data

surrounding regions. Detailed modeling studies [25, 26] have shown that resource exploitation can be economically feasible and still be renewable on a reasonable timescale when nonproductive recovery periods are considered.

Future Directions for Geothermal Energy Technologies

Challenges

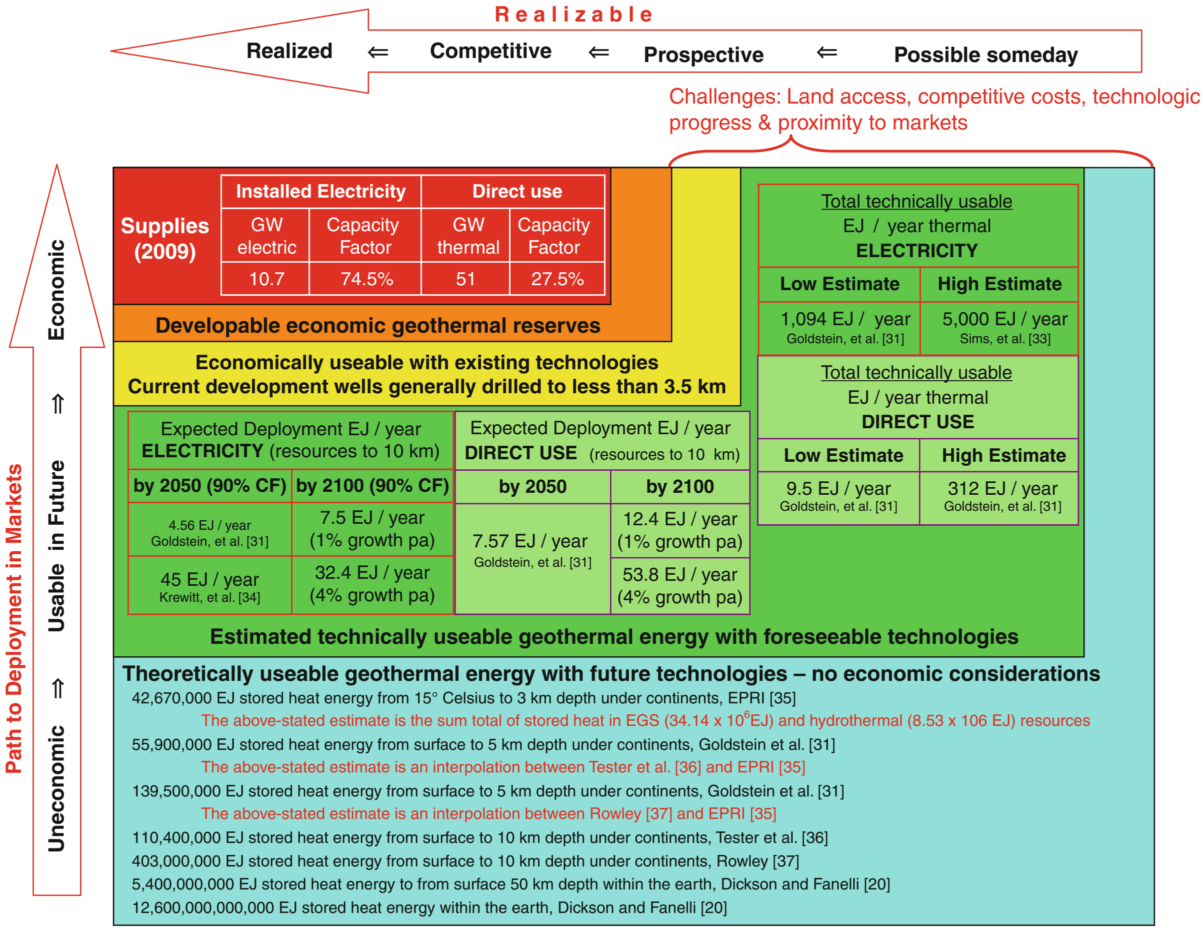
Geothermal resources contain thermal energy that can be produced, stored, and exchanged (flowed) in rock, gas (steam), and liquids (mostly water) in the subsurface of the earth.

With proper management practice, geothermal resources are sustainable and renewable over reasonable time periods. As stored thermal energy is extracted from local regions in an active reservoir, it is continuously restored by natural conduction and convection from surrounding hotter regions, and the extracted geothermal fluids are replenished by natural recharge and by reinjection of the exhausted fluids.

The obvious generalized impediments to massive, global geothermal energy use are:

- Currently insufficiently predictable reliability of geothermal reservoir performance (and in particular, the predicable reliability of engineered geothermal system reservoirs)
- Current costs of geothermal well deliverability (and, in particular, fluid production levels from stimulated engineered geothermal systems and the high costs of drilling deep wells)

Hence, the overarching common and well-justified objectives of global government initiatives



Geothermal Energy, Nature, Use, and Expectations. Figure 2
Potential geothermal energy resources split into categories, e.g., theoretical, technical, economic, developable, and existing supplies for power generation and direct use. All categories for power generation assume a 74.5% capacity factor and 8.1% average efficiency for converting thermal into electrical energy, though both factors will likely improve (increase) in future. All direct use estimates for the future assume an average 31% capacity factor, somewhat higher than the average (27.5%) in 2009 (Adapted from Fig. 1 in Reference [22] and the presentation by L. Rybach published in Reference [23])

are to stimulate technologic and learn-while-doing breakthroughs that will lead to a point where the cost of geothermal energy use is reliably cost competitive and comparatively advantageous within markets.

Priorities to Wider Use of Geothermal Energy

Improved, evermore reliable, cost-effective methods to enhance the productivity of geothermal systems will be essential to the competitiveness of geothermal resource in energy markets. In particular, the commercialization of fracture and/or chemical stimulation methods to reliably create engineered geothermal systems (EGS) independent of site conditions will be one key milestone on the road to great expectations for widespread economic use of geothermal energy. Table 1 results from a scan of the objectives of international geothermal energy fora and defines the top 20 priorities for advancing efficiency and competitiveness in geothermal energy use. This is an update of the priorities presented in Reference [27].

Geothermal Energy, Nature, Use, and Expectations. Table 1 Top 20 research and development priorities for advancing efficiency and competitiveness in geothermal energy use

Openness to cooperation to engender complementary research and the sharing of knowledge	Informing industry, governments, and the public of technologic advances and the merits of using geothermal energy through presentations, publications, websites, submissions to enquiries, and the convening of conferences, workshops, and courses
Creating effective standards for reporting geothermal operations, resources, and reserves	For EGS, improved hard rock drill equipment
Predictive reservoir performance modeling	Improved multiple zone isolation for high-temperature and high-pressure geothermal reservoirs
Predictive stress field characterization	For deep geothermal reservoirs, reliable submersible pumps
For EGS, mitigate induced seismicity	Longevity of well cementing and casing
Condensers for high ambient surface temperatures	For EGS, optimum fracture stimulation methods
Use of CO_2 as a circulating fluid	High temperature logging tools and sensors
Improve power plant design	High temperature flow survey tools
Technologies and methods to minimize water use	High temperature fluid flow tracers
Predict heat flow and reservoirs ahead of the drill bit	Mitigation of formation damage, scale, and corrosion

Expectations for Geothermal Energy Use

The extent or accessibility of geothermal resources will not be a limiting factor for deployment. The key determining factor in the growth in deployment will be the competitiveness of geothermal energy use within local, regional, national, and trade zone markets. The authors have drawn conclusions in regard to future growth in the use of geothermal energy through 2010. The following table (Table 2) provides those global long-term forecasts of installed capacity for geothermal power and direct uses (heat) and of electric and direct uses (heat) generation. Earlier estimates for deployment beyond 2010 that were considered in developing forecasts include References [13, 28–30].

The above-listed forecasts assume improvements in capacity factors power generation from the current average 74.5–90% by 2050, a level already attained in efficient, existing geothermal power generation plants. A more detailed account of actual and expected growth in the use of geothermal energy follows (Table 3). The statistics for installed capacity to generate electricity from geothermal energy, electricity production from those geothermal plants, and capacity factors for geothermal power plants are from the Reference [29] for the term 1995–2005; Reference [13] for 2010 and the Reference [31] for the term 2015–2100. The expressed forecasts for growth from 2050 are based on 1% and 4% average annual growth for the 50 years to 2100.

Next Steps in Global Resource Assessments

A further global geothermal resource assessment is planned under an existing IEA Geothermal Implementing Agreement research annex. This will include a probabilistic range of estimates, e.g., assuming that a log-normal distribution adequately describes the range of recovery of stored heat from a minimum of 0.5% at a 99% probability to a maximum of 40% of stored heat at a 1% probability. This implies: a low-side recovery of 1.34% of stored heat (90% probability), a mid-range recovery of 4.47% of stored heat (50% probability), a Swanson's mean recovery of 6.68% of stored heat, and a high-side recovery of 14.95% of stored heat (10% probability). (Swanson's mean is the weighted approximation for a log-normal distribution equal to the summation of 30% of the 90% probability value, 30% of the 10% probability value, and 40% of the 50% probability value, e.g., $(P90 \times 0.3) + (P10 \times 0.3) + (P50 \times 0.4)$ equals the Swanson's mean value.)

Geothermal Energy, Nature, Use, and Expectations. Table 2 Global forecasts of: installed capacity for geothermal power generation (GWe), installed capacity to deliver thermal energy for direct use (GWt), geothermal power use (TWh_e/year), and geothermal direct uses (TWh_t/year)

Expected world use	2020		2030		2050		2100	
	Direct (GWt)	Electric (GWe)	Direct (GWt)	Electric (GWe)	Direct (GWt)	Electric (GWe)	Direct (GWt)	Electric (GWe)
Capacity	160.5	25.9	455.9	51.0	800	160.6	1,316–5,685	264–1,141
Expected global use	**TWh_t/year**	**TWh_e/year**	**TWh_t/year**	**TWh_e/year**	**TWh_t/year**	**TWh_e/year**	**TWh_t/year**	**TWh_e/year**
	421.9	181.8	1,998.8	380.0	2102.2	1266.4	3,457–14,940	2,083–9,000
	EJ/year	**EJ/year**	**EJ/year**	**EJ/year**	**EJ/year**	**EJ/year**	**EJ/year**	**EJ/year**
	1.52	0.65	4.41	1.37	7.57	4.56	12.4 to 53.8	7.5 to 32.4

Geothermal Energy, Nature, Use, and Expectations. Table 3 Actual (from 1995 to 2010) and expected (from 2015 to 2100) growth in the use of geothermal energy

Year	Installed capacity actual or mean forecast (GWe)	Electricity production actual or mean forecast (GWh/year)	Capacity factor (%)
1995	6.8	38,035	64
2000	8.0	49,261	71
2005	8.9	56,786	73
2010	10.7	67,246	75
2015	18.5	121,600	77
2020	25.9	181,800	80
2030	51.0	380,000	85
2040	90.5	698,000	88
2050	160.6	1,266,400	90
2100	264–1,141	2,082,762–8,999,904	90+

Key Points

- With its natural thermal storage capacity, geothermal is especially suitable for supplying both base-load electric power generation and for fully dispatchable heating and cooling applications in buildings, and thus is uniquely positioned to play a key role in climate change mitigation strategies [32].
- Direct use of geothermal energy for heating and cooling, including geothermal heat pumps (GHPs), is expected to increase to 7.86 EJ/year (~815 GWt) by 2050 and between 12.9 EJ/year (with 1% growth per year) and 55.9 EJ/year (with 4% growth per year) by 2100. Marketing and multiple internationally competitive supply chains will underpin this growth. This expectation is supported information published by Reference [6].
- Power generation with binary plants and total reinjection will become commonplace in countries without high-temperature resources.
- Geothermal energy utilization from conventional hydrothermal resources continues to accelerate, and the advent of EGS is expected to rapidly increase growth after 10–15 years putting geothermal on the path to provide an expected generation global supply of 4.56 EJ/year (~160 GWe) by 2050 and between 7.5 EJ/year (with 1% growth per year) and 32.4 EJ/year (with 4% growth per year) by 2100.
- Geothermal energy is expected to meet between 2.5% and 4.1% of the total global demand for electricity by 2050 and potentially more than 10% by 2100. It is also expected to provide about 5% of the global demand for heating and cooling by 2050 and, potentially, more than 10% by 2100. Geothermal energy will be a dominant source of base-load renewable energy in many countries in the next century.
- In addition to the widespread deployment of EGS, the practicality of using supercritical temperatures

and offshore resources is expected to be tested with experimental deployment of one or both a possibility by 2100.

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Geothermal Field and Reservoir Monitoring

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Article Outline

Glossary

Anchor grouting Concrete pumped into the rocks around the upper part of the well to anchor the well and well cellar to the near-surface rock formations.

Aquiclude A geological formation (or formations) which will not transmit water; a barrier to vertical movement of geothermal fluid.

Aquifer A geological formation (or formations) which contains water or geothermal fluid and will allow fluid movement.

Baseline Data set acquired before exploitation begins, against which any future measurements are compared.

Benchmark Permanent survey mark, often consisting of a stainless steel pin set in a concrete block or in the concrete base of a pipeline support.

Bleed A well that is throttled back to a minimum flow is said to be "on bleed." It is often risky to completely shut down a geothermal production well because it may be difficult to restart. Bleeding also keeps the wellbore heated which minimizes corrosion.

Deep liquid level Boundary between the two-phase and deep liquid zones.

Deep liquid zone Region of single phase liquid conditions below a two-phase (liquid and vapor) zone.

Developer Company or organization which locates or uses geothermal energy for domestic or industrial purposes.

Dryout The process whereby liquid saturation in the pores decreases and the vapor saturation increases, as a result of a decrease in pressure.

Epicenter The point on the Earth's surface directly above the hypocenter or focus of an earthquake.

Geothermal system A body of hot water and rock within the Earth.

Go-devil A tool for determining wellbore clearances or for scraping out obstructions from a well or pipeline.

Groundwater Water, generally cold and of meteoric origin, which resides in near-surface aquifers and is often used for domestic and industrial purposes.

High-temperature system A geothermal system, or part thereof, containing fluid having a temperature greater than 150°C; c.f. *low-temperature system* in which the temperature is less than 150°C. Note, however, that this temperature value is arbitrary and that different authorities adopt different values, or divide the range into low, intermediate, and high temperature.

Hypocenter The focus or focal point of an earthquake (x, y, z) c.f. epicenter (x, y).

Injection (syn. reinjection) The process of returning waste water from a geothermal power station or industrial process back into the ground. This generally occurs around the edges of the field and may not be into the production aquifer from which fluid is drawn off to the power station.

Injection aquifer The formation into which injected fluid is put. Generally this has high porosity and permeability.

Liquid-dominated system A geothermal system, or part thereof, in which the pressure is hydrostatically controlled; c.f. *steam (vapor)-dominated system*, where the pressure is steam-static.

Make-up well Well drilled to replace production lost from an existing production well, due to decreases in fluid temperature or pressure.

Perched aquifer An aquifer of limited lateral extent which is separated from an underlying body of groundwater by unsaturated rock.

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Permeability A measure of the capacity of a geological rock formation to transmit a fluid.

Production zone That region (depth) of the geothermal reservoir from which most of the production of fluid occurs.

Reservoir The region of a geothermal system from which geothermal fluid is withdrawn, or is capable of being withdrawn.

Residual (liquid) saturation The amount of liquid that remains in the pores (as % of pore volume) which decreases in pressure will not vaporize. The liquid saturation level below which vaporization of liquid will not occur.

Steam zone A region of the reservoir in which steam (vapor) is the pressure-controlling phase.

Trigger point A measured value at which it is considered action needs to be taken to prevent or avoid some detrimental occurrence happening, or exceeding some predetermined limit.

Two (2)-phase zone A region where the liquid and vapor (steam) phases of water coexist in pores or fractures.

Vadose zone The region of unsaturated rock and soil between the ground surface and the shallow groundwater level.

Waste water Geothermal water from which energy has been extracted and is no longer required. This may be separated water, or steam which has passed through turbines or a binary plant and been condensed.

Definition of the Subject and Its Importance

Geothermal systems are dynamic entities in which the liquid and vapor phases of water are the main mobile constituents. In their natural state these are generally in a quasi steady-state condition, when considered over a long period of time (>1,000 years). However, when fluid is withdrawn for the purpose of extracting energy then changes may occur within the system. These changes can result in a variety of environmental effects some of which are undesirable and so to manage the extraction of energy in a sustainable and environmentally responsible way it is necessary to monitor the changes. By monitoring the changes with time it is possible to understand and model the effects these changes may have on the environment and take steps to minimize any undesirable effects in a timely manner. Changes may also have engineering implications for a geothermal development, especially for a power station. One example is a decrease in the pressure of steam supplied to the station that may necessitate replacement of the original turbines by those designed to operate at lower pressures. At the start of production at Wairakei (New Zealand) in 1958, the high-pressure (HP) turbine inlet pressure was 1.25 MPa, but by the late 1970s the pressure had fallen to about 0.7 MPa, and the HP turbines were taken offline and the wells derated to intermediate pressure [1]. Another example is a change in enthalpy due to a change in the steam-water ratio that may affect the efficiency of a modular binary plant designed for a specific steam-water mixture.

Introduction

In a typical high-temperature geothermal system used for electrical power generation, a large mass of hot water is withdrawn from an area and the cooler, waste water is injected in a different location, and this can give rise to significant changes within the system and at the surface. However, in low-temperature systems or where only heat (no mass) is extracted, the changes may be small and negligible.

Purposes and Principles of Monitoring

Purposes of Monitoring

Where significant changes occur, or it is anticipated they might occur, a developed geothermal system will be monitored to:

1. Obtain data on which rational and informed resource management decisions can be made by developers and regulatory authorities.
2. Verify that management decisions are having the desired outcomes.
3. Enable the public to have confidence in the environmental management process.
4. Assist in building up knowledge of geothermal systems and how to develop them in a sustainable and environmentally responsible way.

Basic Principles

Ideally, monitoring begins before development starts so that a good baseline is obtained. It is not possible to go back in time, so many different eventualities need to be considered and a fully integrated monitoring program needs to be developed and begun before large-scale productions starts.

Monitoring should be conducted at a frequency sufficient to enable natural variations to be distinguished from exploitation-induced changes.

The data collected needs to be interpreted and regularly compared with predetermined "trigger points." No change may be as important as some change, and is not a valid reason for stopping monitoring, although the frequency of measurement may be reduced after a long period of no change.

Data need to be reliable. Equipment should be calibrated regularly and operated by a competent person. Since monitoring may continue over a long period of time, it is important that the same techniques are used such that a valid comparison can be made between early and recent data.

Monitoring Program Planning

A geothermal monitoring program is likely to extend for several decades, therefore all observations and measurements need to be carefully documented in a suitable archive. During this time there will probably be staff changes and therefore there needs to be a written set of instructions about how and when measurements will be made, so that measurements at different times are compatible with each other. Monitoring sites need to be clearly marked and monitoring facilities (e.g., groundwater monitor wells) need to be maintained. Experience has shown that large-scale geothermal developments often start as a small development and increase in size incrementally. Furthermore, as production wells decline new wells are drilled to maintain steam quantities deliverable to the power station. These engineering activities may result in monitoring sites being altered or destroyed, so it is important that the baseline data set has sufficient redundancy to allow for such loss without seriously compromising its integrity.

Interpretation of Monitoring Data

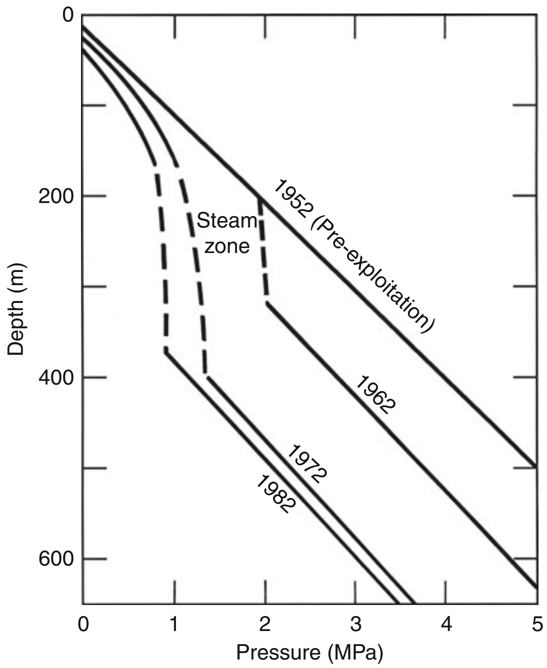
Generally the process of collecting monitoring data is relatively easy, however, correct interpretation of the results may be difficult. Often the first problem in interpretation is separating natural variations from those induced by utilization of the field. Further complexities may be introduced by other human activities, for example, pumping of water supply wells for irrigation or drinking water for animals, and diversion or damming of rivers may cause groundwater level changes. The effects of some anthropogenic changes may be difficult to measure or even estimate. Another significant problem is that what is measured inside a drillhole may not represent what is occurring in the rock outside the drillhole, because as fluid passes from the rock into the hole it may change in character.

Down-Hole Monitoring

A variety of down-hole monitoring techniques have been developed, many originating from the oil industry, to determine reservoir changes. Ideally, down-hole monitoring is undertaken in nonproducing wells, or production wells that are shut down or on "bleed." However, making the measurements is the simplest part of the process because often the casing configuration of the well can strongly influence the data obtained and needs to be taken into account. Furthermore, there is a problem in that conditions within a wellbore may be different from those in the rock outside the wellbore.

Pressure

Changes in fluid pressure with depth and time are key indicators of reservoir changes, especially in high-temperature liquid-dominated systems. In their natural, predevelopment state the reservoirs in such systems contain boiling liquid water, with pockets of 2-phase conditions in the upper part. Pressures are near boiling point for depth. Extraction of fluid, and the concomitant decrease in pressure, generally causes these pockets of 2-phase conditions to coalesce into a continuous 2-phase zone and then expand (both horizontally and vertically). As the pressures fall the liquid saturation in the pores and fissures decreases, and eventually steam becomes the pressure-controlling phase in the upper



Geothermal Field and Reservoir Monitoring. Figure 1 Sketch showing the variation of pressure with depth at different times during early development of the Wairakei geothermal field, New Zealand (Taken from [2]). Note increase in thickness of the steam zone (1962, 1972) followed by slight decrease (1982)

part of the zone, giving rise to a steam zone in which there is negligible change in pressure with depth (Fig. 1). Continued pressure decreases (e.g., Fig. 2) may lead to cool inflows which resaturate the pores in the 2-phase zone, resulting in a rise in the deep liquid level and an increase in pressure in the deep liquid zone (although pressures may continue to decrease in the overlying steam and 2-phase zones).

A continuous vertical profile of pressure variation with depth is made using high-pressure high-temperature (HPHT) wire line equipment, now generally using quartz pressure transducers.

Temperature

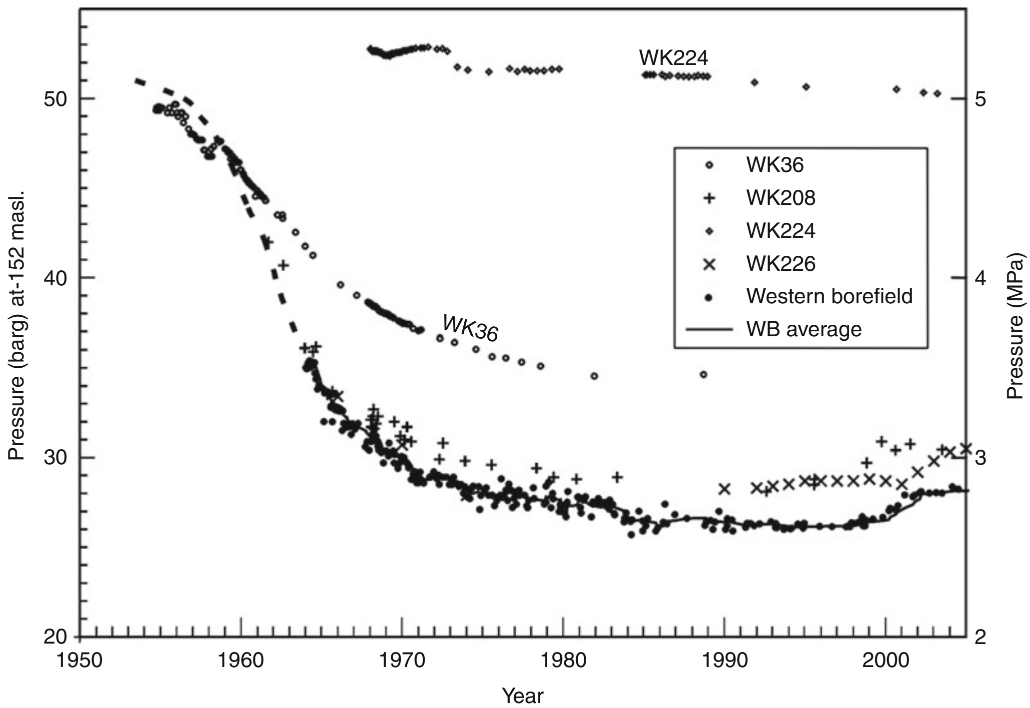
Changes in fluid temperature within the geothermal reservoir are of vital importance in managing and guiding future development of a geothermal field. After drilling and output testing, a geothermal well is generally left for several weeks for the temperatures of the wellbore fluid to stabilize and achieve thermal equilibrium with the surrounding rock formations. A profile of temperature variation with depth is then made using HPHT wire line equipment, and repeated at intervals of time. For production wells this temperature logging can only be done when it is possible to shut the well down for enough time for thermal equilibrium to occur.

Initial temperature logs of deep geothermal wells rarely show a consistent increase of temperature with depth: regions of cooler values (reversals) reveal cool inflows and regions of hotter values reveal feed zones (Fig. 3). When interpreting temperature logs it is important to take into account the casing pattern; in uncased regions or zones of slotted casing, there may be flows within the wellbore between different formations (see below) that result in the measured temperatures being different from the rock outside the wellbore.

Some production wells may experience significant decreases in feed temperatures with time as a result of cold downflows, lateral inflows of cooler water, or changes in the relative amounts of contribution from feed zones of different temperature (Figs. 4 and 5). Lateral inflows of cooler water may be associated with the return of cooler injected water along high permeability paths. Temperature and chemistry monitoring can detect such returns and so guide the location of drilling of make-up wells.

Flow

Changes in fluid mass and volumetric flow rate, and the proportion of vapor (steam) to liquid (water), for individual production wells are also important for managing and guiding the development of a liquid-dominated geothermal field. Measuring the mass and volumetric flow in a well or pipeline is not easy, especially two-phase flow, and accuracies can vary [4]. One modern method, a vortex mass flowmeter, is based on the phenomenon of vortex shedding. A non-streamlined body, called a “shedder bar,” inside the pipeline causes an alternating series of vortices to be shed from each side of the body. The distance between successive vortices on each side is related to the fluid velocity, and is measured by a sensor behind the shedder bar. From the velocity measurement, and simultaneously measured temperature and pressure values, the



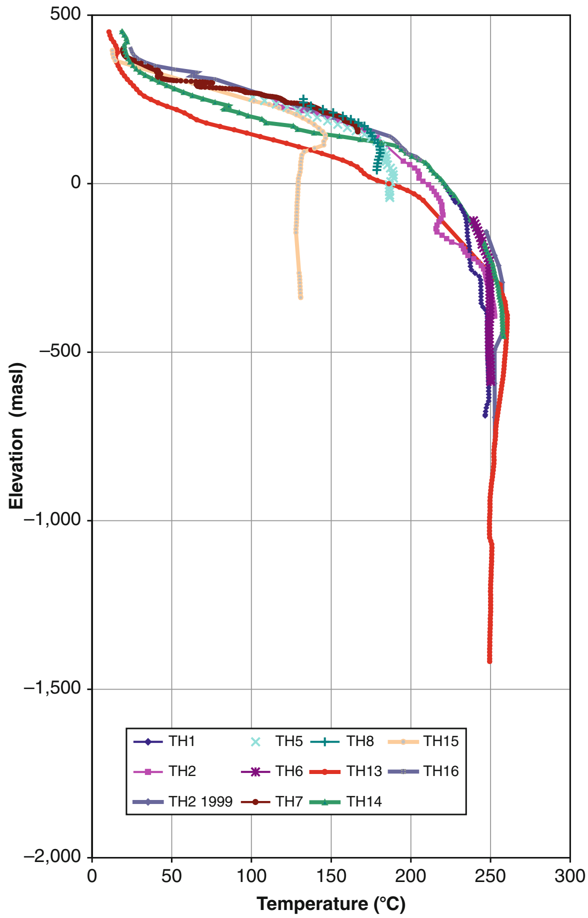
Geothermal Field and Reservoir Monitoring. Figure 2
Changes in deep liquid pressure with time in Wairakei geothermal field (Taken from [3]). Pressure: 1 bar = 0.1 MPa. Testing of exploration wells began in the early 1950s and production started in 1958. Well WK224 (top) lies outside the field

volumetric and mass flow rates can be calculated. Flow rates within a well can be measured using a spinner type or hot-wire flowmeter. Generally these measurements are made at low flow rates or when the well is shut down and the instrument is passed through a gland at the wellhead. Another type of flowmeter used is the Coriolis or Inertial flowmeter which directly measures the mass flow rate [5]. It has one or more bent, straight, or U-shaped vibrating tubes in the fluid stream, and as the fluid passes through the tubes, they twist. The amount of tube twisting is directly proportional to mass flow. This meter can also be used for heat measurement of low-pressure, superheated steam. The chief advantage of a Coriolis flowmeter is in providing highly accurate measurements of mass flow rate without flow conditioning or accessory devices such as pressure or temperature measurement.

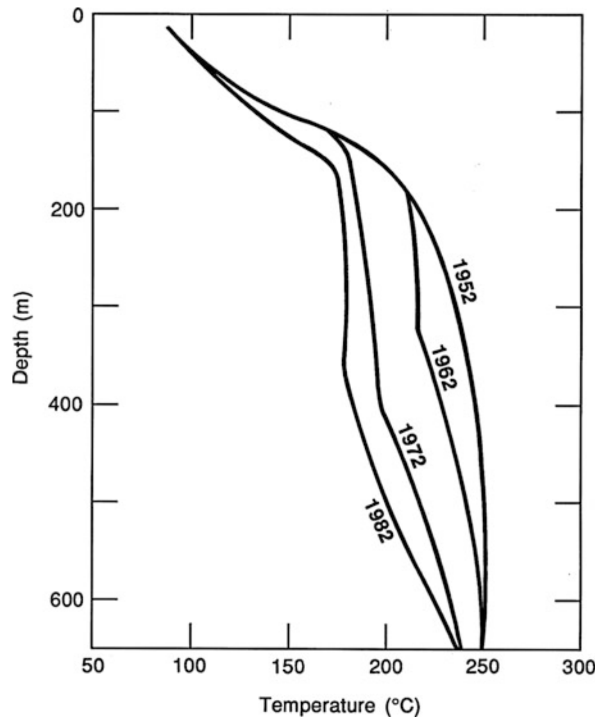
Fluid flow within a wellbore may be complex. In a flowing production well there may be several feed zones at different depths, each contributing to the total flow measured at the wellhead. In a non-flowing geothermal well, the high aspect ratio of the cased part of the wellbore precludes thermally generated fluid movement. However, in an open (uncased) or slotted region of the well there may be fluid movement between formations having different temperatures and physical properties; fluid may exit from one aquifer, travel up or down the wellbore, and enter another (thief zone). Repeated wire line flowmeter measurements may be made to detect changes in flow from the different feed zones over time, or before and after maintenance on a well, and for finding holes in casing that have developed due to corrosion.

Fluid flow within the rock matrix can be measured using chemical tracers introduced into a well and their arrival time and concentration measured in other wells (see below).

Generally, for a high-temperature geothermal field the mass flow rates will decline, and (for liquid-dominated wells) the enthalpy will increase over time, unless injection returns cause an increase in mass flow and decline in enthalpy.



Geothermal Field and Reservoir Monitoring. Figure 3 Variation of temperature with depth in exploration drillholes in Tauhara geothermal field, New Zealand. Note the differences between wells and that in some wells (especially TH2, between −100 and −200 m) there are temperature reversals due to cool inflows

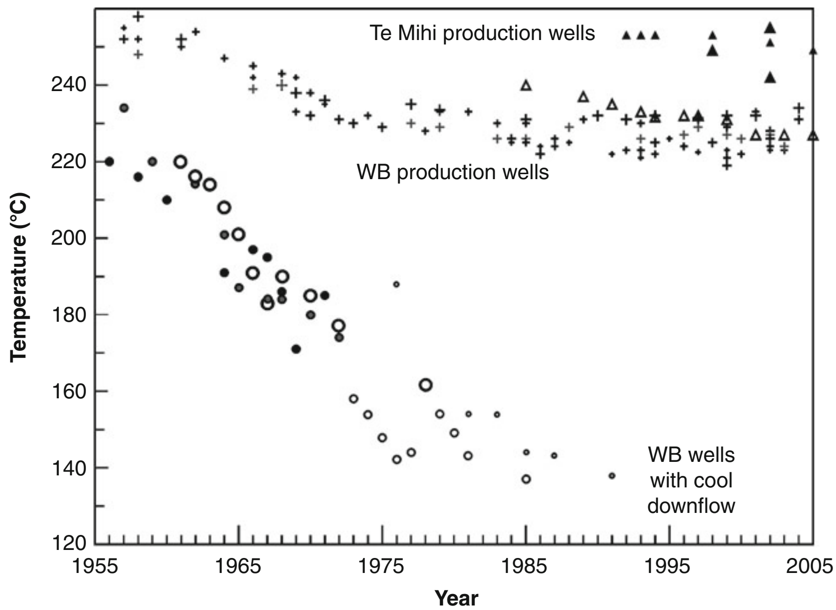


Geothermal Field and Reservoir Monitoring. Figure 4 Sketch showing variation of temperature with depth in some wells (Eastern borefield), at different times during early development of the Wairakei geothermal field, New Zealand (Taken from [2])

Casing Integrity

Over a period of time, steel well casing and piping, and concrete anchor grouting can become damaged as a result of corrosion (stress or fatigue), scaling, or ground deformation. Corrosion may occur on the inner surface of the casing as a result of acidic fluids flowing up from deep feed zones, or it may occur on the outer surface of the casing and attack grouting as a result of acidic fluids being present in a formation through which the well passes [6, 7]. Corrosion is present in most geothermal wells, even low-temperature and low-enthalpy wells, but is generally more of a problem in deep, high-temperature, and high-enthalpy wells tapping CO_2-rich and acidic fluids. Mechanical deformation (breaks, buckling) may occur in wells subject to significant ground deformation [8].

Casing damage is detected by running a mechanical caliper tool with flexible fingers up and down the hole, or by running a “Go-devil” tool down the hole. Detailed determination of the damage may then be investigated using a video camera or a sonic borehole televiewer. Damage to near-surface (<10 m depth) casing can be repaired by excavating a pit around the well and replacing the damaged casing. To repair deeper damage it may be necessary to run new liner of smaller diameter inside the damaged production casing, apply casing patches or install expandable casing.



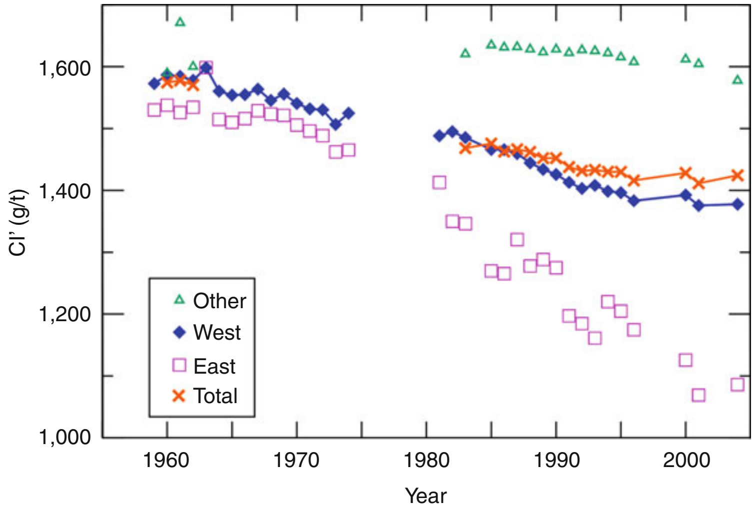
Geothermal Field and Reservoir Monitoring. Figure 5
Changes in production temperatures with time in Wairakei geothermal field (Taken from [3]). WB: Western Borefield. Note the large decrease in temperature of fluid from wells having cool downflows, whereas other production wells have experienced only a small temperature decline and temperatures have remained near constant since about 1975

Fluid Chemistry

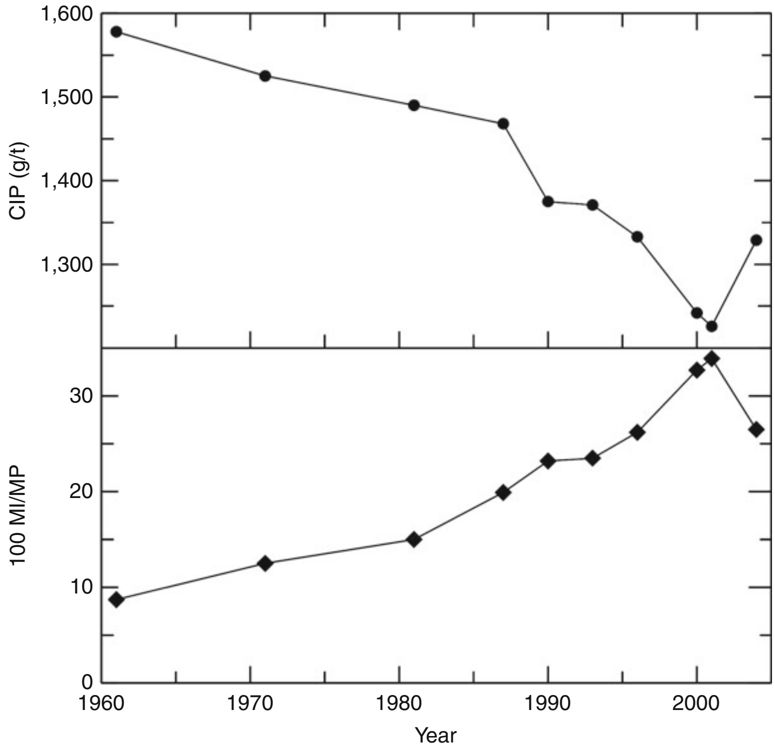
The chemical composition of geothermal production fluids may change with time due to dilution and cooling of the reservoir fluids, resulting mainly from the invasion of cool and less-mineralized waters (Fig. 6). Regular measurement of the chemistry of liquid and vapor samples of fluids from selected wells provides information about changes in the reservoir. The data are also used to examine the need for and effectiveness of chemical dosing to prevent corrosion, and to monitor mineral deposition in the wells and pipework. However, interpretation of chemical changes is not necessarily straightforward because the chemistry of production fluids may vary between wells, and as the relative amounts of production from each well change with time (due to supply requirements) so the total chemistry may appear to change.

Samples of geothermal fluid may be taken either from within the wellbore (i.e., down-hole) or at the surface. Down-hole samples are taken using a special sampling device that captures the geothermal fluid in its in situ, undisturbed state; i.e., before phase separation, irreversible thermal cycles, or chemical reactions have occurred [10, 11]. Samples are usually taken at different depths in a well to determine the changes that occur as the fluid ascends the well. At the surface, a small sample of the two-phase geothermal fluid is drawn off from the flowing well and passed through a small separator which separates the liquid (water) from the vapor (steam). The liquid (water) fraction is then cooled by passing it through a water-cooled coil and analyzed by standard techniques. The vapor (steam) fraction is passed into an evacuated glass flask containing a caustic solution to absorb acidic gases (carbon dioxide, hydrogen sulfide); the solution is then analyzed by titration. Trace gases (Ar, He, N) remain in the top of the flask and are removed and analyzed using a gas chromatograph [12].

In high-temperature liquid-dominated geothermal systems, chloride is a major chemical species and an important indicator of changes in the reservoir fluid. A decrease in the chloride content may indicate dilution due to an influx of cold groundwater (Fig. 7), and an increase may indicate injection returns.



Geothermal Field and Reservoir Monitoring. Figure 6
Changes with time in average chloride content (corrected for aquifer steam loss) of production fluid from different parts of Wairakei geothermal field (Taken from [9]). “West” and “East” refer to Western and Eastern borefields, respectively; “other” refers to the Te Mihi borefield, from where production began in the early 1980s



Geothermal Field and Reservoir Monitoring. Figure 7
Changes with time of the average chloride content of production well fluid (ClP) at Wairakei (upper) and in the amount of cold inflow (%) into the production zone computed from the chloride changes (lower) (Taken from [9]). The increase in the chloride value after 2000 is attributed to a larger proportion of deep water coming from a new production area (Te Mihi) and to more injected water (beginning 1995) reaching the production wells

In fields where the geothermal fluid resides or passes through limestone, the fluid may become saturated in calcium carbonate ($CaCO_3$), which precipitates as calcite in the wellbores and pipelines as temperatures and pressures decline. This precipitate, known as scaling, is a serious problem because it reduces the fluid flow and particles of precipitate may flake off and enter the turbines causing damage. Monitoring of the carbonate helps identify problem wells and enable scaling rates to be determined.

Tracer Tests

Although primarily used for reservoir characterization purposes, tracer tests [13–15] may be used for reservoir management, particularly if major changes are made in the development of a field. A tracer test involves inserting a finite slug of a chemical or radioactive material ("tracer") into an injection well and measuring the time for it to appear, and its concentration, in production and monitoring wells. Tracer tests to evaluate the flow patterns between injection and producing wells are common practice in oil and gas field operations. A wide variety of chemical tracers have been used including: hydrofluorocarbons (tetrafluoroethane, trifluoromethane), naphthalene disulfonate, noble gases (neon, xenon), potassium halides (KBr, KI), rhodamine WT, and fluorescein. Fluorescein is the most commonly used tracer in liquid-dominated geothermal reservoirs because it is sufficiently stable to be used in reservoirs as hot as 250°C; it has a detection limit of approximately ten parts per trillion using conventional spectrofluorimetry; and can be detected using a simple, inexpensive, and easily operated filter fluorometer. Iodine 131 has been used as a radioactive tracer [16]. Some tracers travel preferentially in the vapor (steam) phase, others in the liquid (water) phase. By repeating tracer tests it may be possible to determine changes in fluid flow paths, particularly "short circuiting" of injected fluids from new injection wells directly to production wells.

Surface Monitoring

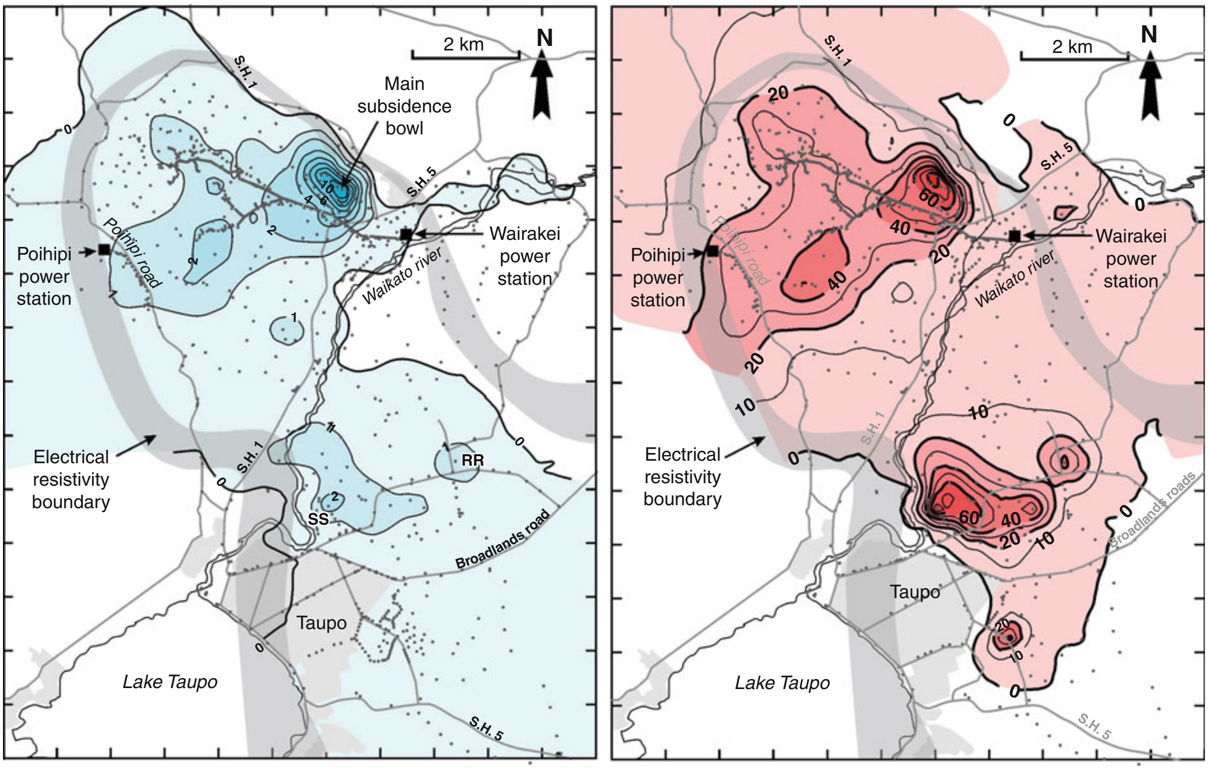
Flow Rate

Monitoring fluid flow rates at the wellhead of production and injection wells is a basic monitoring tool which can indicate changes in the performance of individual wells and of total field performance. Sudden unexpected changes in flow rate from an individual well may indicate damage to the well casing. Gradual decreases in flow rate may indicate a fall in reservoir pressure in the vicinity of the well feed zone(s), or a change in the relative contributions of supply from different feed zones.

Ground Surface Movements

In a few geothermal fields, notably some of those in New Zealand, there have been significant ground subsidence (up to 15 m) and horizontal deformation (up to 2 m) associated with production.

At Wairakei field (New Zealand), deformation was originally noticed when concrete drains became broken, and subsequently pipework has been mounted on roller supports to accommodate movement, although from time to time it has been necessary to remove and insert sections of pipe. Vertical deformation is measured by repeat surveys using an optical level to measure changes in elevation between permanent reference points such as benchmarks, referenced to a stable point outside the field. The frequency of surveys depends on the rate of subsidence and the location of the subsidence area. At Wairakei, the main steam lines are leveled every 2 years, and the whole field about every 4 years. In some fields, where there are not extensive amounts of surface vegetation, it has been possible to determine subsidence using interferometric synthetic aperture radar (InSAR) [17–20]. At Wairakei-Tauhara field (New Zealand) there have been small areas of intense subsidence within the field since measurements began shortly after production started in 1958 [21]. In this field the subsidence has occurred mainly in about four localized "subsidence bowls," but over the remainder of the field the subsidence has been less than 1 m (Fig. 8). At the center of the main subsidence bowl the rate of subsidence increased to a maximum of over 450 mm/year in the late 1970s but has since decreased to about 50 mm/year (Fig. 8). The location of the bowls and their centers does not correspond to areas of maximum production; the center of the main subsidence bowl lies about 500 m from the original area of production. The cause of the subsidence at Wairakei-Tauhara and Ohaaki is associated with draining, and consequent compaction, of rocks of locally high



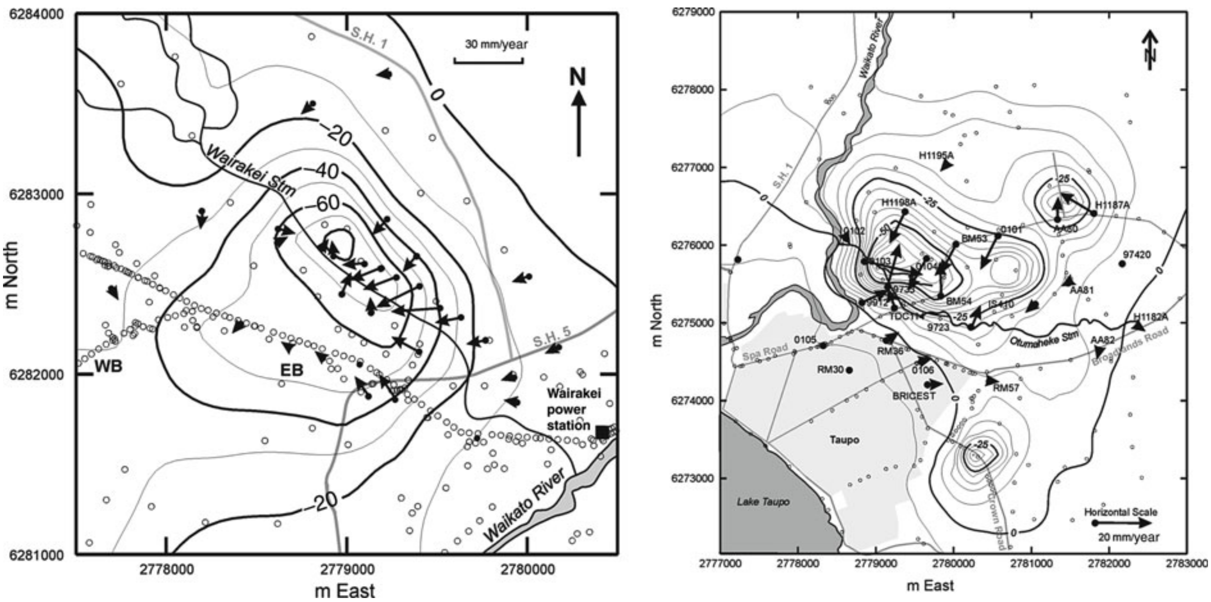
Geothermal Field and Reservoir Monitoring. Figure 8
Ground subsidence (left; m) and subsidence rates (right; mm/year for 2001–2005) at Wairakei-Tauhara geothermal field, New Zealand (Taken from [21]). *Dots* indicate survey points. Note that the intense subsidence is confined to several isolated subsidence bowls: Main; SS Spa Sights; RR Rakanui Road

compressibility within formations above the reservoir, due to a decrease in pressure within the steam zone in the upper part of the reservoir. Casing deformation indicates these rocks lie at about 100–300 m depth. However, the reason for the localized distribution of high compressibility in these rocks remains a puzzle; other parts of the same formations do not have high compressibility. At Mokai field (New Zealand), there has been subsidence of up to 0.20 m around the injection wells, associated with cooling and thermal contraction of rocks in the injection aquifer.

Horizontal deformation is measured using theodolites or Geodimeters to measure changes in angles or distances between permanent reference points, or using global positioning system (GPS) techniques. Generally the reference points are permanent markers specifically installed for the purpose. At Ohaaki field (New Zealand), these consist of a concrete post made from a drainage pipe (approximately 600 mm diameter), mounted vertically, set in a concrete pad, and filled with concrete. A threaded pipe is set in the upper surface of the post to allow a theodolite, Geodimeter, or a target to be mounted on the post. At Wairakei-Tauhara field (New Zealand), the largest horizontal movement rates have been 25–30 mm/year and have occurred at the edges of the main subsidence bowl where the lateral changes in subsidence (tilt) have been the greatest [21]. The horizontal movement vectors generally point toward the center of the subsidence bowls (Fig. 9). The overall pattern of horizontal movement has not changed greatly with time, but the rates of movement have declined as the subsidence rates have decreased.

Groundwater

Near the ground surface above most geothermal reservoirs there is generally a complex sequence of groundwater aquifers containing cold or warm waters (and in



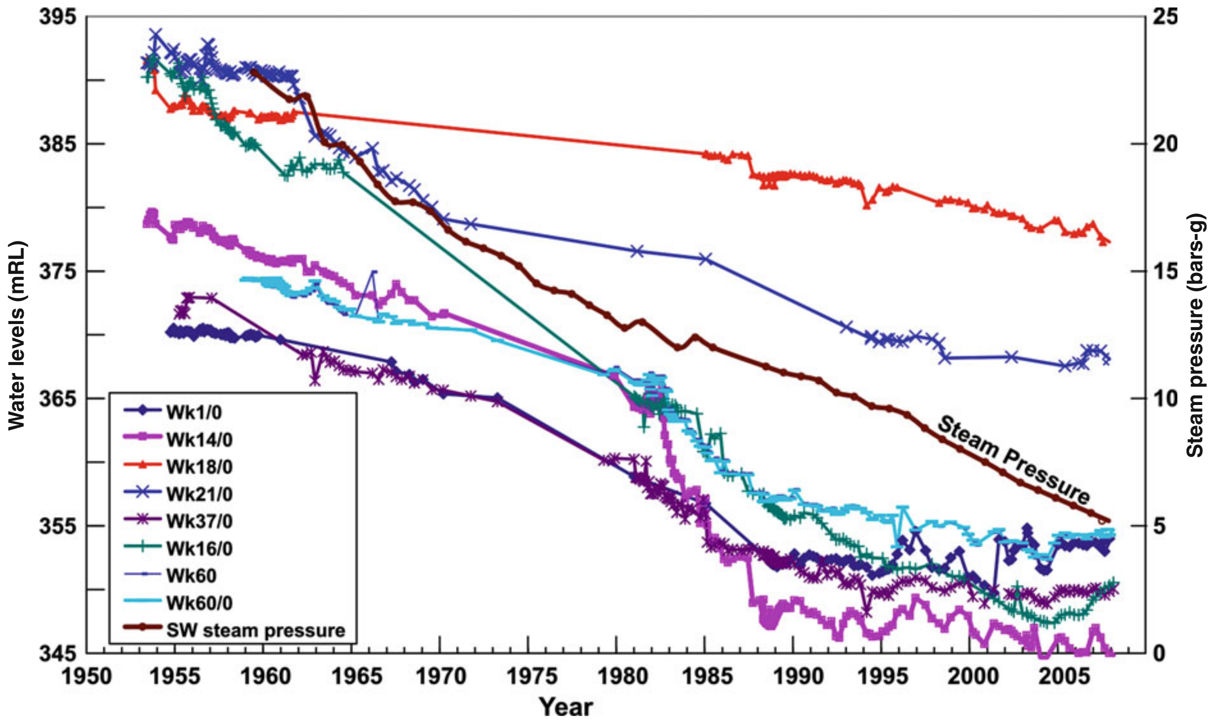
Geothermal Field and Reservoir Monitoring. Figure 9
Horizontal deformation vectors (*arrows*) at subsidence bowls in the Wairakei-Tauhara geothermal field (Taken from [21]). Solid contours indicate rates of ground subsidence (mm/year) determined at benchmarks (*open circles*). Note the vectors point to the center of the subsidence bowl, and have greatest amplitude on the flanks of the bowl

places hot water and steam) which are often a source of potable water or used for industrial and domestic purposes (heating, cleaning). The aquifers are usually separated from each other by aquicludes.

These shallow aquifers can be affected by production from the deeper geothermal reservoir and hence many regulatory authorities require water levels, water chemistry, and temperatures in the aquifers to be monitored periodically. Monitoring is usually done using shallow wells drilled specifically for the purpose. These holes are generally about 3–5 cm diameter and are generally drilled vertically using a small truck-mounted auger. The holes usually have solid casing in the Vadose Zone and slotted or screened casing from the water table to the bottom. Where several groundwater aquifers are present several monitor holes are drilled and care is taken in each to adopt a casing pattern that monitors a specific aquifer and ensures that the well does not result in interaction between separate aquifers, i.e., draining of an upper into a lower aquifer. In places where the ground temperature is less than about 50°C, plastic (PVC or ABS) casing is used, but for ground temperatures greater than this value steel casing is used. The open area of the screened casing should approximate the natural porosity of the rock formation, and the slots should widen inward to minimize plugging of the slots by fine formation material. Over a long period of time, fine silt and debris migrate through the screened casing and are deposited at the bottom of the hole; so the hole is generally drilled 5–10 m deeper than the natural water table.

Water levels are measured using a simple electric circuit device lowered down the well; this is powered by a small battery and contact with the water closes the circuit. Alternatively, a water level recorder can be installed which is comprised of a pressure transducer coupled to a data logger. Measurements are generally made at set times during the year to determine and correct for seasonal variations.

Changes in groundwater level (piezometric surface) can occur as a result of pressure declines in the deep geothermal reservoir. At Wairakei (New Zealand), decreases in groundwater level of up to 30 m have been recorded in the Eastern Borefield, an area where thermal features were fed by conduits from the deep reservoir [22] (Fig. 10). As pressures in the upper part of the reservoir decreased, the flow of geothermal fluid



Geothermal Field and Reservoir Monitoring. Figure 10
Changes in shallow groundwater level with time in the Eastern Borefield at Wairakei geothermal field (Taken from [22])

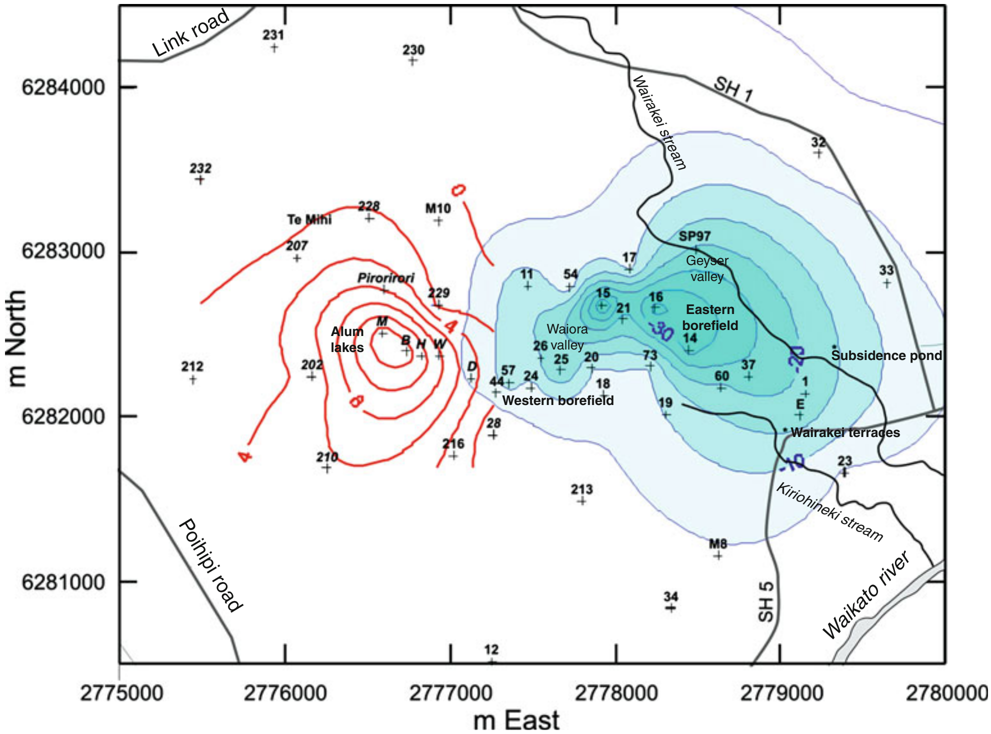
up conduits to the surface declined and eventually ceased. This allowed shallow groundwater to drain down the conduits, resulting in local regions of depression of the groundwater surface (Fig. 11). In some cases, where the near-surface geology is complex, these changes can be localized, especially where perched groundwater aquifers are present [23].

The temperature of groundwater is measured in shallow monitor holes using a digital thermometer and probe. Sometimes the temperature is measured not only at the water surface but also deeper in the monitor hole, to enable a temperature profile in the water to be obtained.

Samples for chemical analysis are obtained from groundwater monitor holes after water level and temperature measurements have been made. However, care must be taken not to sample stagnant water in these holes; only after five to ten wellbore volumes of water have been removed and naturally replaced should a sample be collected. Removal of stagnant water and collection of the samples is generally done using a small portable electric pump. Parameters that are usually measured are: pH, chloride, lithium, sodium, potassium, magnesium, sulfate (SO_4), total silica (SiO_2), total bicarbonate (HCO_3), and fluoride. In addition, measurements of stable isotopes $\delta_{18}O$, δ_2H, and tritium are sometimes made.

Microgravity

Exploitation of high-temperature geothermal resources usually involves withdrawing fluid from one area (production area) and, after using it to generate electricity or provide heat, injecting the liquid back into the ground in another area (injection area). This generally results in changes in mass (and corresponding density changes) in these areas, and hence small changes in the force of gravity at the surface (Figs. 12 and 13). The amount of gravity change in the production area will be related mainly to the amount of recharge, and to

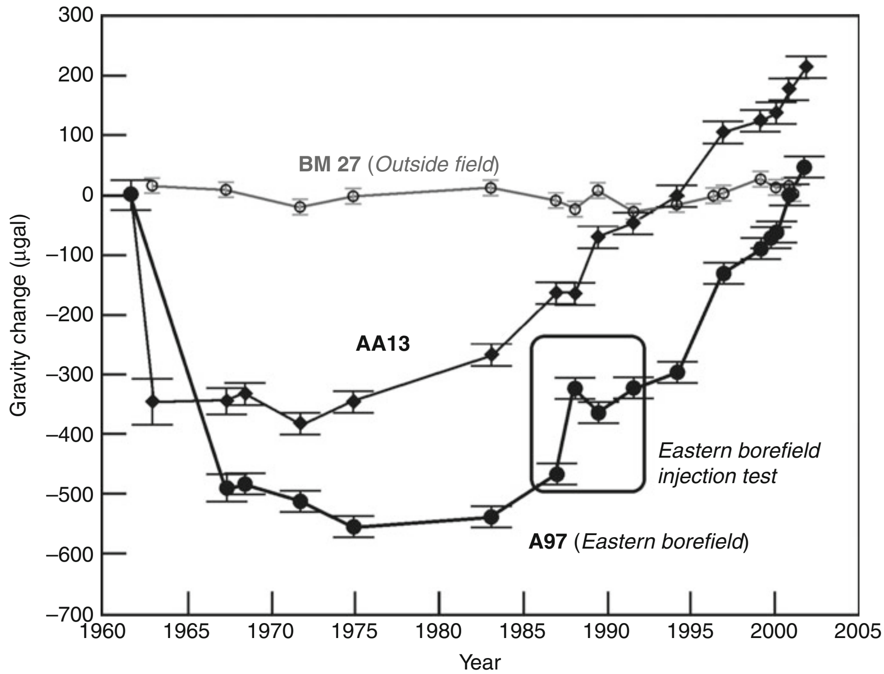


Geothermal Field and Reservoir Monitoring. Figure 11
Changes in shallow groundwater level (m) in at Wairakei geothermal field (Taken from [22]). Changes in the Eastern Borefield (blue contours) are for the period 1956–1995; changes in the Alum Lakes area (red contours) are for the period 1999–2006. Crosses indicate monitor wells; labels indicate well numbers (see Fig. 9); letters in the Alum Lakes area indicate thermal pools

changes in the proportions of liquid water and steam in the production zone.

The changes in gravity are measured at permanent reference points such as survey benchmarks throughout and beyond the field boundaries using a portable gravity meter. Generally a relative type of gravity meter is used which measures differences in gravity from a stable, reference point outside the geothermal field, although in some instances absolute gravity meters have been employed. Measurement precision is generally 5–10 μGal (5–10 × 10^{-8} m/s^2). A baseline survey is made at 50–150 points prior to exploitation, and the survey repeated at intervals of 2–5 years afterward. Within each survey, corrections are made for the gravitational effects of changes in the position of the Moon and Sun (Earth tide) and for tares (jumps in zero point of the meter resulting from knocks). In determining the gravity differences between surveys (gravity changes) the data are corrected for the gravitational effects of ground elevation changes (subsidence), gravity changes at the reference point, and changes in groundwater level and temperature.

From the gravity changes it is possible to determine a field-wide value for recharge by numerical integration of the changes and application of Gauss's Theorem [25]. This method is completely independent of any assumptions about fluid density, depth of production, permeability, or porosity; its accuracy is limited only by the precision of the gravity measurements, and errors inherent in the integration of the data. Gravity change



Geothermal Field and Reservoir Monitoring. Figure 12
Changes in gravity (µgal) associated with production at Wairakei geothermal field, New Zealand. Benchmarks A97 and AA13 lie in the Eastern borefield from which most production was obtained between 1958 and the 1980s. Note the increase in gravity since the late 1970s, associated with resaturation of the production aquifer (Taken from [24])

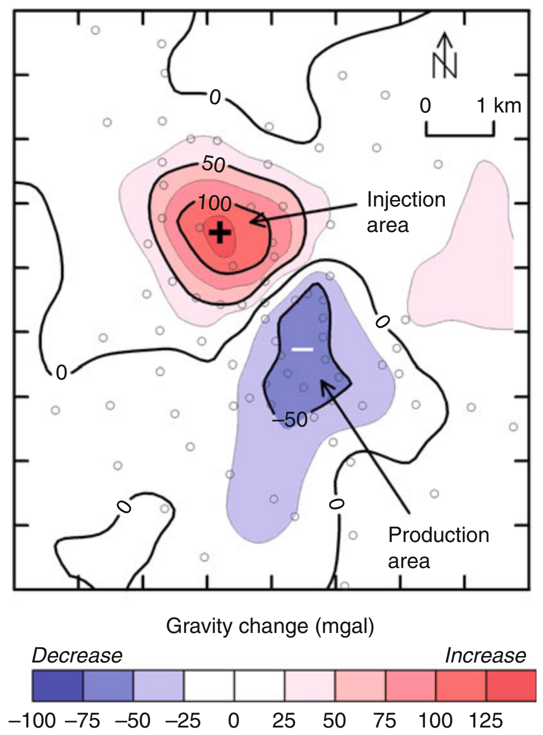
measurements also may provide: field-wide and local values for recharge of fluid into a geothermal system; information about changes in saturation in different parts of the two-phase zone; a test of complex, three-dimensional, numerical reservoir simulation models for exploitation of a field [26, 27]; information about the location and movement of injected fluid [28]; and estimates of reservoir parameters such as permeability (k), permeability-thickness (kh), and storativity (φch) [29].

Gravity change data can also be used to discriminate between two (or more) numerical reservoir simulation models for exploitation of a field. Such models are important in guiding development of a field. The models for high-temperature liquid-dominated fields predict the development and extension of 2-phase conditions and subsequent changes in saturation (and hence density and gravity changes) which involve assumptions about the geometry of the field, various reservoir properties, and behavior of the field during exploitation. Discrepancies between the theoretical (model-derived) and measured gravity changes may indicate that assumptions made in setting up the models are wrong.

Another important use of gravity change data is to track the path of injected water. If the waste liquid water is injected into a region of 2-phase conditions the liquid is cooler, and hence denser than the fluids present, and tends to sink toward the bottom of the zone. If the rocks do not have isotropic permeability the liquid will move more rapidly along paths of high permeability and in response to any pressure gradients that might be present; this movement being reflected by the gravity changes.

Electrical Resistivity

Most high-temperature geothermal fields, particularly liquid-dominated fields, are delineated by a boundary



Geothermal Field and Reservoir Monitoring. Figure 13 Gravity changes at Mokai geothermal field, New Zealand, between 1997 and 2004. *Open circles* indicate measurement points; contour interval 25 μgal (25×10^{-8} m/s^2). Data has been corrected for the effects of small amounts of ground subsidence

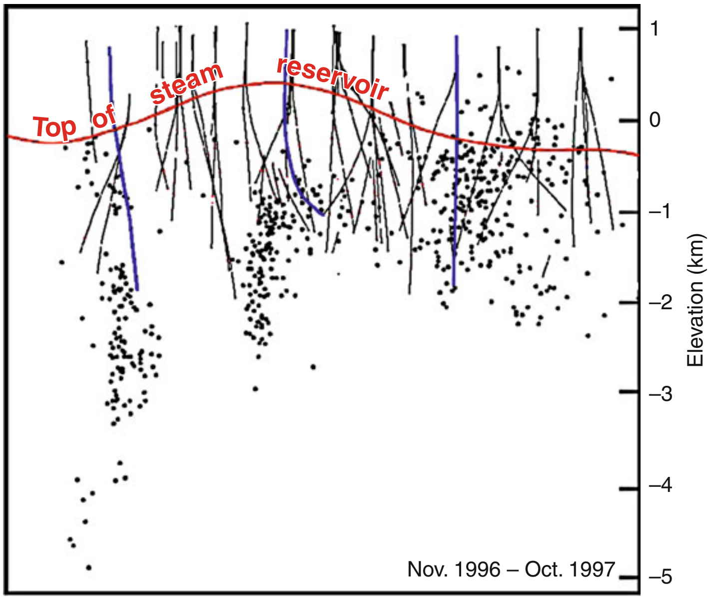
zone in which the electrical resistivity increases from low values (1–50 Ωm) inside the field to high values (>200 Ωm) outside the field. If production from the field causes significant decreases in fluid pressure in the upper part of the reservoir, there may be an influx of cool water from outside the field. If such an influx is large enough and at shallow depth then there may be an apparent lateral shift in the electrical resistivity boundary zone where this influx is occurring. Such a shift may be detected, before the cool water reaches production wells, by repeating electrical resistivity surveys across the boundary zone. Another situation where repeating electrical resistivity surveys may be useful is where hot saline waste water is injected into cold water aquifers outside the field.

Induced Seismicity

In many high-temperature geothermal fields exploitation can result in an increase (above the normal background) in the number of small magnitude earthquakes (micro-earthquakes) within the field (Fig. 14) [30]. Induced seismicity occurs in both liquid- and vapor-dominated high-temperature fields, and in enhanced geothermal systems, but has rarely been observed in low-temperature fields. The increase is caused mainly by injection because when injection starts or is increased the number of local micro-earthquakes increases, and when injection decreases or is stopped the number of small earthquakes decreases [30, 31]. The main cause of the micro-earthquakes is high wellhead injection pressures that increase the pore pressure at depth, particularly in existing fractures, which allows movement to suddenly release stress and generate an earthquake. Thermal stress associated with the injection of cool waste water into a hot fluid aquifer may also trigger earthquakes in the vicinity of the injection wells.

The micro-seismicity is generally monitored by an array of seismometers (vertical- or three-component) placed in shallow drillholes (to minimize the effects of anthropogenic "noise"). Usually the signals from each seismometer are telemetered in real time to a central recording apparatus – this ensures consistent relative timing of the signals which is critical for determining the location (hypocenter and epicenter) of the earthquake. The hypocenter of each seismic event is then computed from the relative time differences of the arrival of the shock wave at each seismometer, assuming a specific local seismic velocity model [32]. The seismic velocity model is calculated either by inverting the seismic data collected over a period of time [33], or from explosions set off in drillholes. The magnitudes of the micro-earthquakes within the geothermal field are determined by comparison with the magnitudes of large local events as determined by national or regional seismic networks.

During a 4½ year period in which the mass of water injected at The Geysers field increased and decreased (due to seasonal power loading), the number of events measured by a detailed seismic network (Fig. 15) appeared to be related more closely to the injection rates rather than (steam) production rates [34].



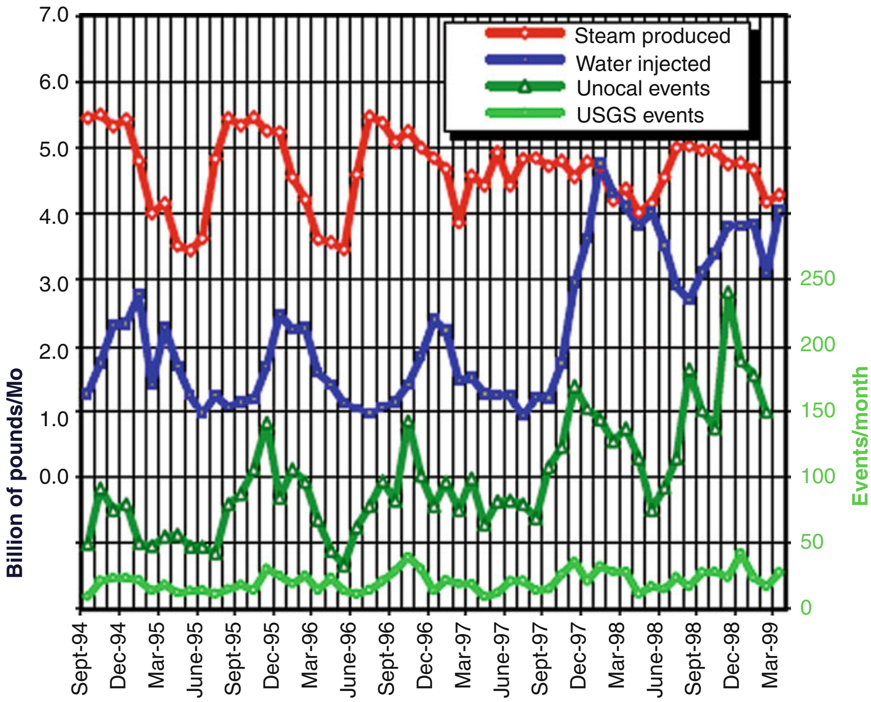
Geothermal Field and Reservoir Monitoring. Figure 14
Cross section through The Geysers field (California, USA) showing locations of earthquakes (*black dots*) during a 12-month period. Injection wells are shown in blue. Earthquake hypocenters and wells within 2,000 ft (600 m) of the section line have been projected onto the cross section. Note that the earthquake hypocenters extend to depths greatly below the bottom of some injection wells (Taken from [34])

Real-time monitoring of micro-seismicity can be used to minimize the felt intensity of shaking by reducing or stopping injection if the number of events exceeds certain predetermined thresholds – this is known as “traffic light control” of injection [30, 35].

Thermal Features

Many geothermal fields, especially high-temperature liquid-dominated fields, are manifested at the surface by natural thermal features such as geysers, hot pools, hot springs, mud pools, fumaroles, and areas of thermal ground. Changes in these features with time during production from the field can indicate changes in the geothermal reservoir from which fluid is being withdrawn, although in some cases it may be difficult to separate natural changes from production-induced changes. A wide variety of thermal features can be monitored, however, the most sensitive and easiest to monitor are geysers, hot pools, and hot springs.

Geysers Geysers occur in high-temperature geothermal fields. They are the most spectacular and the most valued of natural thermal features (for cultural and economic reasons) and are the most sensitive to production-induced changes in a geothermal system. Geysers are generally monitored by measuring changes in the eruption period (time between the start of successive eruptions), usually by a simple device that continuously measures the temperature of water in a channel leading from the geyser. Increases in the eruption period of geysers may be indicative of pressure decreases in the reservoir: increases in the eruption period of two geysers at Wairakei field were measured (Fig. 16) prior to their demise during the time of preproduction well testing (test discharge period) [36].

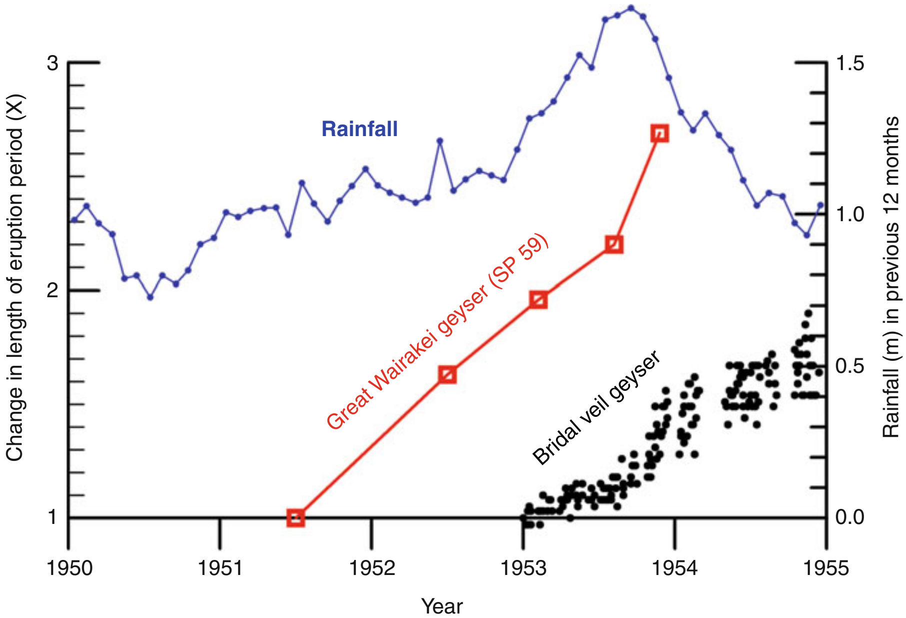


Geothermal Field and Reservoir Monitoring. Figure 15
Comparison of changes in the number of seismic events detected with variation in the amount of injection at The Geysers field, USA (Graph taken from [34])

It is difficult to measure the volume of erupted water because of flashing to steam during the eruption, and evaporation from or absorption into the rocks surrounding the vent after the erupted water has fallen to the ground. If the geyser erupts frequently, it is feasible to measure eruption height by using a video camera; however, the volume and height of geyser eruptions often vary naturally due to wind gusts and to seasonal changes in rainfall.

Springs and Hot Pools Hot springs and hot pools are also associated mainly with high-temperature geothermal fields and have important cultural and economic value [37]. Regular or continuous monitoring of the temperature, chemistry and flow rate of hot springs, and the temperature and water level in hot pools are generally made. Decreases in these parameters are also indicative of changes which may lead to the demise of these features.

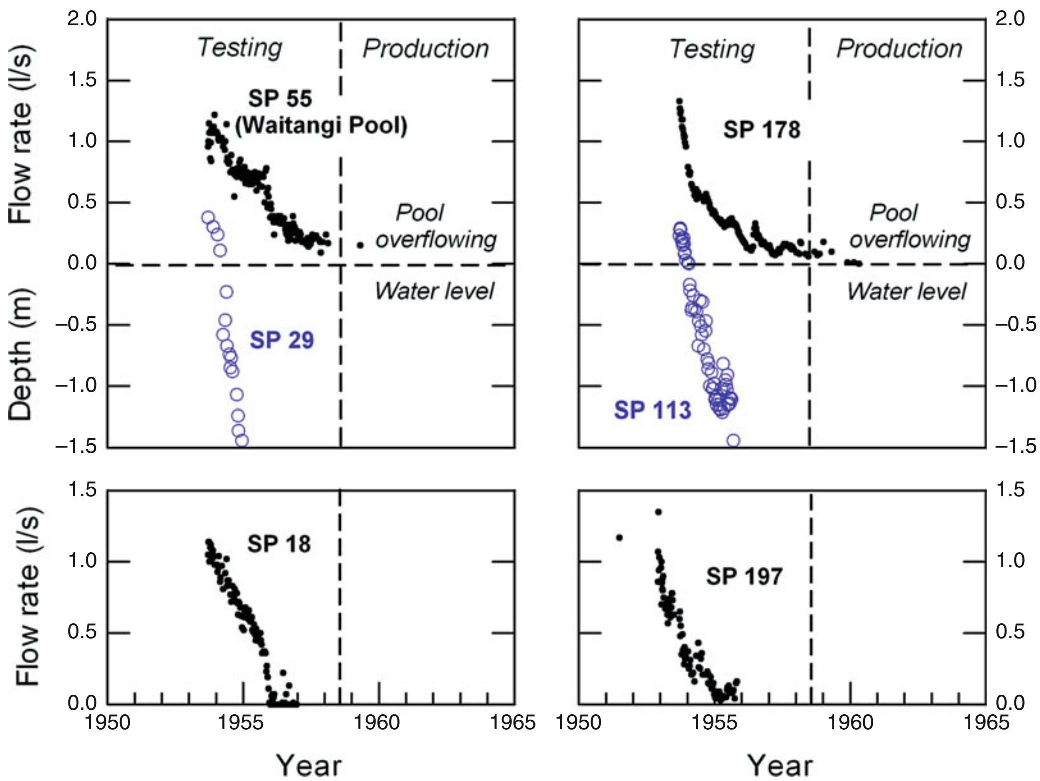
The temperature of water emerging from the ground in hot springs and in pools is measured using a variety of commercially available devices employing thermistors or thermocouples. The temperature data are often measured continuously and captured in a data logger. The flow rate of springs and the rate of outflow from hot pools are generally measured by constructing a channel to take all the water from the feature and pass it through a V-notch weir. The basic principle is that flow rate is directly related to the water depth above the bottom of the V. The V-notch design causes small changes in flow rate to have a large change in depth allowing more accurate measurement than with a rectangular weir. From the measurement of the height of the water flowing through the V-notch and the angle of the V, the flow rate can be calculated.



Geothermal Field and Reservoir Monitoring. Figure 16
Changes in length of eruption period (T/T_0) of two geysers in Geyser Valley at Wairakei geothermal field (New Zealand) during the time of preproduction test discharges. Eruption periods are normalized to T_0 = 12.5 h for the Great Wairakei Geyser, and T_0 = 39 min for the Bridal Veil Geyser. Rainfall data are monthly running totals of rainfall in the previous 12 months. Note the steady increase in length of eruption period with time (Taken from [36])

However, the value obtained may need to be adjusted to take into account rainfall and evaporation from the surface of the pool and channel before the water reaches the V-notch. To monitor changes in the chemistry of the water, samples are taken and analyzed in a laboratory; usually chloride content is the main chemical species measured. If flow into a hot pool decreases sufficiently such that evaporation exceeds inflow, then the water level in the pool may fall below the overflow and the water level may temporarily or permanently fall. A difficulty in interpreting temperature and flow rate data is separating natural changes from production-induced changes; this can be minimized by taking the measurements at a frequency sufficient to determine natural changes caused by changes in rainfall and groundwater level.

At Wairakei geothermal field, the flow rate from hot springs in Geyser Valley declined (Fig. 17) during the time of preproduction test discharges of exploration wells in the Waiora Valley [36]. Initially, the changes were small and isolated and were thought to be caused by natural climatic variations. It was not until much later that it was recognized that the changes to the hot springs were associated with changes in the deep reservoir resulting from fluid withdrawal some distance away. A decline in thermal features in producing high-temperature geothermal fields appears to be associated mainly with a decline in reservoir pressure. As the pressure declines, so also does the amount of geothermal fluid reaching the surface and hence the thermal features decline in size and vigor. If pressures fall further then the features may die and the flow may reverse, with cold groundwater flowing down into the reservoir; once this situation has occurred it may take a long time to resurrect the features. Monitoring of changes to hot springs and hot pools may enable declines to be recognized quickly and remedial action taken.



Geothermal Field and Reservoir Monitoring. Figure 17
Changes in outflow rate and water level with time in some hot pools at Geyser Valley, Wairakei (Taken from [36]). Note how, as well testing proceeded, the outflow rates declined and the springs stopped flowing. In the pools associated with springs SP 29 and SP 113, the water level dropped below the outlet until water stopped flowing and they dried up

Future Directions

Reservoir monitoring will probably expand in scope and increase in frequency in the future because regulatory authorities are generally becoming more concerned about environmental effects. There are also commercial and economic effects which may result in more monitoring. Monitoring data help improve numerical simulation models which developers use to identify the potential effects of changes in production and injection. The modeling is not only for planning and operational purposes but also to help secure loan funding for future expansion at the most favorable interest rates because bankers seek to reduce risk, and monitoring and modeling help in the reduction of risk.

Significant improvements in monitoring are likely to be the development of down-hole instrumentation capable of withstanding high temperatures for long periods of time. However, the problem of relating what is measured in a drillhole to what is occurring in the rock outside the hole will still remain.

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Geothermal Power Capacity, Sustainability and Renewability of

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Article Outline

Glossary

Discharge A measure of the flow rate of steam, water, or heat discharged at or near the ground surface from a subsurface geothermal reservoir.

Geothermal The naturally occurring heat found beneath the surface of the Earth, ultimately originating from the internal magmatic processes of the Earth's core. A geothermal energy project utilizes the hot water or steam found within certain large bodies of rock, referred to as a geothermal reservoir.

Power capacity The amount of energy produced per unit time, or the amount of the electric power capacity that a power generation facility is designed to produce.

Recharge Natural influx of hot fluids into a geothermal system.

Renewable A natural energy resource that is inexhaustible or can replenish itself over time.

Specific heat The amount of heat required, in calories, to raise the temperature of 1 g of a substance by 1°C.

Sustainable A natural energy resource which, if managed carefully, will provide the needs of a community or society indefinitely, without depriving future generations of their needs.

Thermal anomaly A departure from the normal or expected temperature in the subsurface as distinguished by geological, geophysical or geochemical means, which is different from the general surroundings.

Thermal conductivity A measure of the ability of a material to conduct heat.

Definition of the Subject and Its Importance

Geothermal energy is the heat energy of the earth, produced through wells as hot water or steam. Geothermal power capacity is this energy extraction rate (whether as thermal energy or equivalent electrical energy produced per unit time), expressed in Watt or an equivalent unit. The vast content of heat energy within the earth is limitless for all practical purposes, but the geothermal power capacity available from the earth is constrained by various technological and economic limits to the utilization of this energy. Given a geothermal power generation scheme (for example, a district heating scheme using geothermal water or an electric power operation using geothermal water or steam), the issue is how sustainable, technically and economically, the scheme would be and to what extent this energy supply is naturally renewable.

For the purposes of this entry, sustainability is defined as the ability to economically maintain an installed power capacity, over the amortized life of a power plant, by taking practical steps, such as, drilling "make-up" wells as needed to compensate for resource degradation (pressure decline, well productivity decline, or cooling of the produced hot water or steam). Renewability is defined here as the ability to maintain an installed power capacity indefinitely without encountering any resource degradation; this renewable power capacity at a geothermal site is generally too small for commercial development of electrical power capacity, but may be adequate for district heating or other direct uses of the geothermal energy.

Introduction

As per above definitions, it is argued below that only a portion of the sustainable geothermal power capacity at a site is renewable; yet, geothermal energy is widely believed to be entirely renewable. Therefore, it is

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important to objectively review the concepts of sustainability and renewability of geothermal power capacity and their quantification. These issues are addressed below.

Concepts of Sustainability and Renewability

Many articles have been published on the renewability and sustainability of geothermal energy [1–7]. However, no universally accepted definitions of the words "renewability" and "sustainability" as regards geothermal power seem to exist and definitions used often have ambiguities. For example, Axelsson et al. [3] defines "renewable" generation capacity (Fig. 1) as:

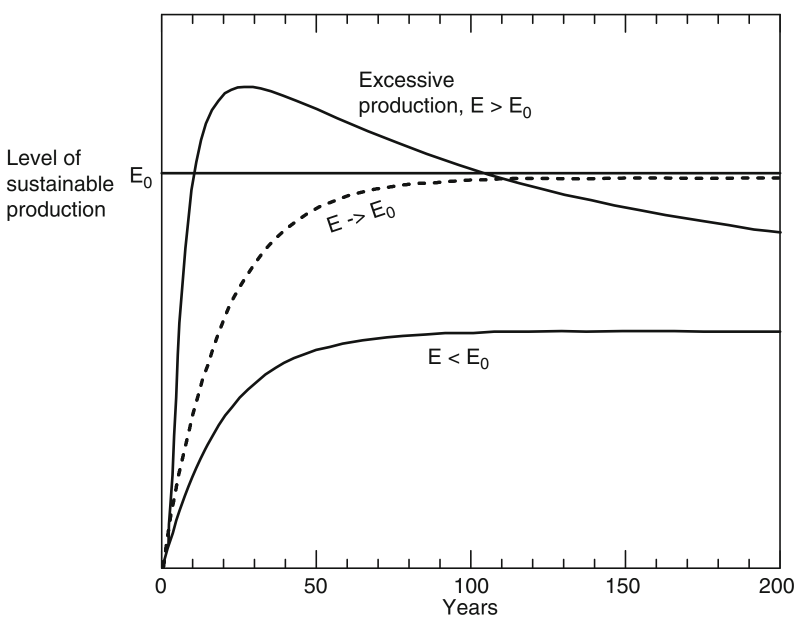
- The energy extracted from a renewable energy source is always replaced in a natural way by an additional amount of energy, and the replacement takes place on a similar time scale as that of the extraction.

And Axelsson et al. [3] define "sustainable" generation capacity as follows (Fig. 1):

- For each geothermal system, and for each mode of production, there exists a certain level of maximum energy production, $\mathbf{E_0}$, below which it will be possible to maintain constant energy production from the system for a very long time (100–300) years. If the production rate is greater than $\mathbf{E_0}$ it cannot be maintained for this length of time. Geothermal energy production below, or equal to $\mathbf{E_0}$ is termed **sustainable production**, while production greater than $\mathbf{E_0}$ is termed **excessive production**.

An objective review of the above definitions is presented below, extracted largely from an earlier paper by the author.

The above definition of renewability essentially equates renewable capacity to the natural heat recharge rate (conductive plus convective) into a geothermal reservoir, which remains constant over geologic time (that is, tens of thousands of years) in the natural state. This recharge rate can be estimated for an actual reservoir by numerical simulation of the natural, steady-state heat flow, and measured temperature and pressure distributions, within the system. The renewable capacity is, however, frequently too small for commercial development because of the unfavorable economy of scale in capital and operation costs and relatively high cost of infrastructure development associated with a small power project. The above definition



Geothermal Power Capacity, Sustainability and Renewability of. Figure 1
Illustration of the definition of sustainable and excessive production levels [3]

of sustainability may perhaps be acceptable for non-electrical uses of geothermal energy (such as district heating), which are of relatively low intensity and are not capital-intensive, but the definition has inherent ambiguities and limitations for practical applications to the electric power industry. The difference between renewability and sustainability as defined above is a matter primarily of the time scale; as discussed later in connection with a case history presented below, an exploitation level that can be sustained for 100–300 years can most likely be sustained indefinitely. Therefore, for most fields, the above two definitions are essentially identical.

A constant energy production rate over a time span of 100–300 years is reasonable for defining renewability but not sustainability. A power plant can be sustained over a typical amortized life of 20–30 years at a capacity level much higher than the renewable capacity level by make-up well drilling or taking other steps to mitigate resource degradation. Numerical simulation consistently shows that any resource degradation caused over a typical plant life of 20–30 years would essentially disappear within a 100–300-year time frame after the project is shut down; the pressure would return to the original level in about 20–30 years and the temperature within 100–300 years, the actual time taken being dependent on the natural convective heat recharge rate at the site (see, for example, [8]). Therefore, over a 100–300-year time span, commercial exploitation for 20–30 years at the sustainable level should not leave any permanent impact on the resource base. On the other hand, it is likely that producing the reservoir at a level higher than the renewable capacity estimated from natural-state modeling would actually cause an increase in the natural recharge rate of hot water into the reservoir. This has frequently been the author's experience from monitoring many producing geothermal fields; the case history discussed later illustrates this point. Therefore, estimate of renewable or sustainable power capacity from the simulation of the natural state of a geothermal reservoir is conservative; substantial production history is needed to estimate these capacities with any confidence. On the other hand, unless these capacities can be determined to the satisfaction of financial institutions, it is not possible to obtain long-term financing for a power plant; unless a power plant is installed, accumulation of substantial production history is out of the question. This is a fundamental conundrum of the geothermal power industry.

Geothermal reserves are normally expressed in terms of the installed capacity sustainable for the life of a power plant; empirical experience shows this reserve level to be an order of magnitude higher than the renewable level estimated from the natural state of the reservoir; see, for example, Table 1 (to be discussed later). Therefore, if the definition of sustainability in Fig. 1, which is essentially same as renewability, is to be used, the geothermal resource base worldwide should be considered an order of magnitude smaller than is generally accepted today. In other words, exploitation of geothermal resources would be artificially constrained to an order of magnitude lower than the level at which exploitation is readily possible without any long-term negative impact on the resource base. This would make development of many fields for power generation economically prohibitive. Furthermore, this cannot be a socially responsible position considering that a higher rate of exploitation can only reduce the current fossil fuel usage, thus reducing environmental pollution today and saving fossil fuel resources for future generations. As discussed below, there is social virtue in preserving more of fossil fuel resources for the future, and instead, maximizing the use of power from geothermal resources, which are renewable within the 100–300-year time frame.

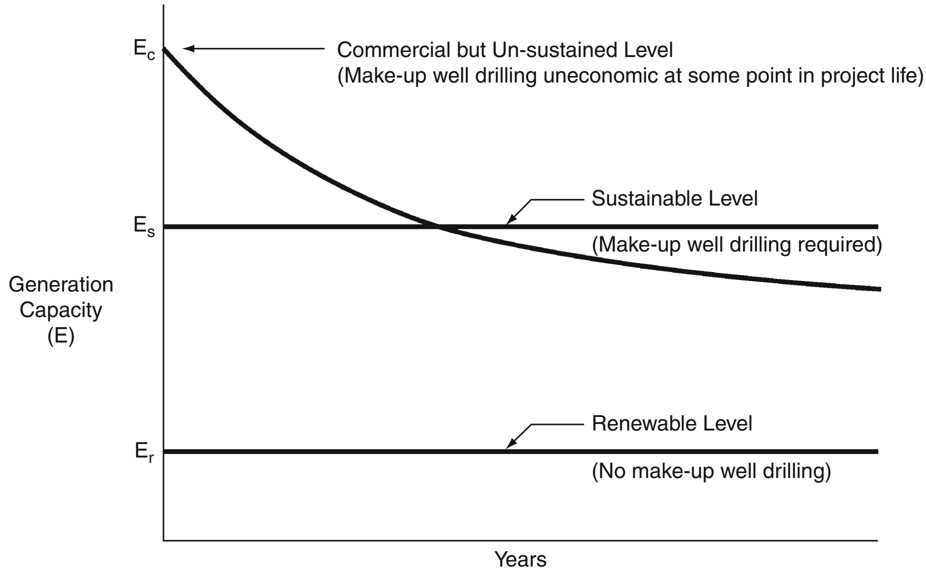
While geothermal power has far less environmental impact than power from fossil fuels, it is inevitable that power derived from fossil fuels will become progressively more environmentally benign in the future. Finally, unlike geothermal, fossil fuels also serve as raw material for petrochemicals and coal-based organic chemicals. While future generations may harness hitherto unforeseen sources of energy, fossil fuels will still be needed as raw material for chemicals. Therefore, one can justify a higher rate of geothermal power use today than adhering to a level that is renewable within the 20–30-year lifetime of a power plant.

With respect to electric power capacity, this entry proposes an alternative, and more practical, definition for sustainability, and also defines a purposefully unsustained "commercial" capacity level (Fig. 2). The former is defined as the ability to economically maintain the installed capacity, over the amortized life of a power plant, by taking practical steps

Geothermal Power Capacity, Sustainability and Renewability of. Table 1 Empirical data on renewable and sustainable capacities [7]

Field	Location	Renewable capacity (MWe)	Sustainable capacity (MWe)	References
Ahuachapan	El Salvador	24.8	95+	[9]
Beowawe	Nevada	1.3	13+	[10]
Cerro Prieto	Mexico	73.3	720	[11]
Desert Peak	Nevada	14	90+	[12]
Heber	California	1.7	70	[13]
Kakkonda	Japan	26.6	80+	[14]
Kawareu	New Zealand	15.5	230	[15]
Krafla	Iceland	5.3	60	[16]
Mammoth	California	25	90+	[17]
Mindanao	Philippines	9.6	102	[18]
Miravalles	Costa Rica	16.5	168	[19]
Mori	Japan	5.4	50	[20]
Mutnovsky	Russia	9.2	100	[21]
Nesjavellir	Iceland	16.6	160	[22]
Ngawha	New Zealand	2.5	30	[23]
Oguni	Japan	8.2	20+	[24]
Onikobe	Japan	2	25	[25]
Roosevelt Hot Springs	Utah	5.3	50+	[26]
San Emidio	Nevada	1.9	10+	[12]
Sibayak	Indonesia	11	30+	[27]
Soda Lake	Nevada	1.6	15	[12]
Stillwater	Nevada	4	40	[12]
Sumikawa	Japan	4	50+	[28]
Takigami	Japan	3	25	[29]
Uenotai	Japan	2.5	25	[30]
Wairakei	New Zealand	46	220+	[31]
Wasabizawa	Japan	5.6	40+	[32]
Zunil	Guatemala	2.44	25	[33]
		Total: 386	Total: 2,056+	

(such as, make-up well drilling) to compensate for resource degradation (pressure drawdown, well productivity decline and cooling). The latter can be defined as a capacity level that is initially kept higher than the sustainable level but may be allowed to decline with time once make-up well drilling, or other measures to mitigate resource degradation, becomes uneconomic at some point in project life. In a socially responsible vein, this declining capacity starting above the sustainable level could be considered commercial only if the



Geothermal Power Capacity, Sustainability and Renewability of. Figure 2
Proposed definitions [7]

levelized power cost is calculated to be lower than that from alternative renewable resources. Even if the power cost at such a commercial level proves higher than that from fossil fuels, this higher capacity can displace fossil fuel usage if power from renewable or environmentally benign resources is given adequate tax breaks (such as carbon credit), market access (such as implementation of "renewable energy portfolio standards"), or price support (such as production tax credit or any direct subsidy) by governments or international agencies.

The appropriate un-sustained but commercial power capacity level can only be arrived at by numerical simulation of the actual production behavior of the reservoir concerned and within the context of the economic realities and market forces. Such a purposefully un-sustained but commercial level is socially beneficial for a market-driven economy because it allows reduction in levelized power cost through accelerated capital recovery while helping to displace the use of fossil fuels. The cumulative energy extraction over the project life at an un-sustained but commercial level need not exceed the cumulative energy that would be extracted at the sustainable level, thus still assuring natural replenishment of the resource base in a 100–300-year time frame. Therefore, such a commercial development level is not only reasonable but also desirable, particularly if one considers the distinct possibility of acceleration of natural recharge of hot water into the reservoir, thus mitigating the impact of a higher initial production rate.

In discussing renewability and sustainability of geothermal energy, interesting analogies have been invoked from time to time by various authors, for example, comparison with mining, management of fisheries, utilization of hydropower, and so on. While all these analogies correspond to some aspects of geothermal energy exploitation, yet another analogy is offered here to elucidate the over-arching concept of sustainability proposed in this entry. A reasonable analogy for renewable capacity would be seasonal harvest of crops while timber harvest would be an appropriate analogy for sustainable capacity, for the timber resource would grow back within a few decades. One could harvest only the annual growth at the tips of the tree branches and keep the forest resource constantly renewable. But is this a reasonable approach to natural resource husbandry? While renewable, annual tree growth can be used as firewood or turned into paper pulp, the forest resource is more valuable to the society if mature trees are harvested for timber and then allowed to grow back. Likewise, constraining geothermal energy exploitation within a continuously renewable level, which is suitable primarily for low-intensity,

non-electrical uses, is neither reasonable nor desirable from a socioeconomic viewpoint. In addition, thinning of a forest accelerates tree growth due to the penetration of more sunlight into the forest; this is a convenient metaphor for the increase in natural recharge rate due to exploitation of a geothermal resource above the so-called renewable level.

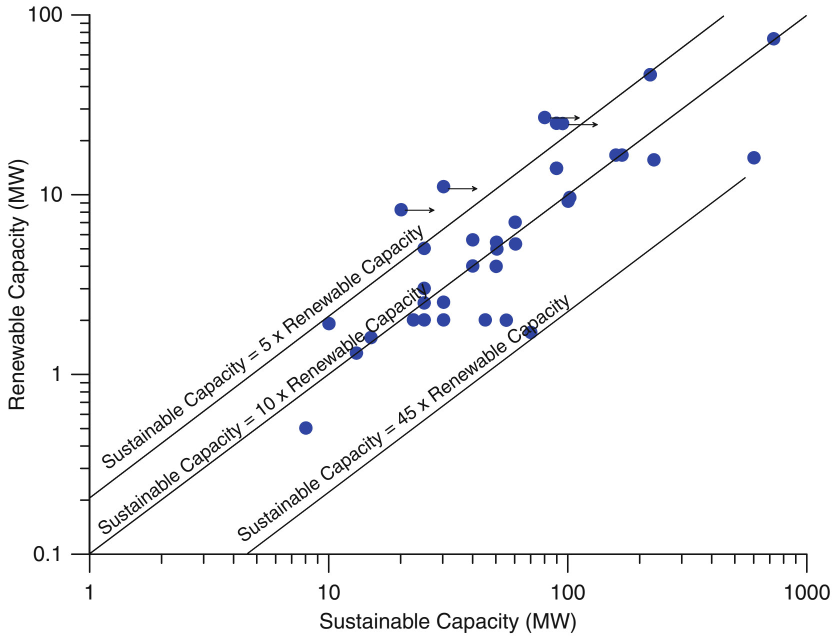
Relation Between Renewable and Sustainable Capacities

This entry considers only liquid-dominated geothermal fields with capacity for supplying electric power, steam-dominated fields being rare occurrences; only six steam-dominated fields have been exploited to date: The Geysers, California; Lardarello, Italy; Matsukawa, Japan; Kamojang and Darajat; Indonesia; and Los Azufres, Mexico. Based on the experience in monitoring many producing geothermal fields for more than 3 decades and conducting dozens of numerical simulation studies of actual reservoirs, the author has observed that the sustainable capacity of a liquid-dominated field is typically an order of magnitude higher than the renewable capacity. The understanding here is that the renewable capacity of a field corresponds to the power capacity equivalent of the natural heat recharge, conductive plus convective, into the system; and sustainable capacity is supported by "mining" (or "harvesting" if one considers a time frame of centuries) of the stored heat in addition to natural heat recharge. To confirm this empirical observation, a review has been made of both published and unpublished results of numerical simulation and heat flow studies of more than half of the approximately 65 liquid-dominated geothermal fields in the world that have supplied commercial power to date and for which reasonably reliable estimate of the natural heat recharge rate could be made. The heat recharge rate was estimated from either numerical simulation of the reservoir or surface heat flow studies, with the reasonable assumption that the rate of natural heat recharge into the reservoir to be equal to the total rate of heat discharge at the surface over the entire thermal anomaly.

Table 1 lists approximate estimates of the renewable and sustainable capacities of 37 geothermal fields from published sources or various archives. The electrical power equivalent (MWe) was approximated from the estimated thermal power capacity based on First and Second Laws of Thermodynamics assuming a rejection temperature of 15°C and a utilization factor of 0.45. The sustainable capacity value for a field in Table 1 was taken as the proven exploitation capacity, unless actual reservoir response and/or simulation studies had indicated the sustainable capacity to be higher. As such, the sustainable capacity values in Table 1 should in general be considered minimum estimates. As mentioned before, this table illustrates that renewable capacities are relatively small compared to sustainable capacities, the total for 37 fields being 386 and 2,056+ MWe, respectively. Furthermore, at the renewable level, most fields would not support commercial power development; for example, if 10 MWe were the smallest commercially developable capacity, only 11 of the 37 fields would qualify.

Figure 3 is a cross-plot of the above-listed renewable and sustainable capacities. The points with arrows in the direction of higher sustainable capacity represent fields for which the presently installed capacity appears manifestly smaller than the sustainable capacity but no estimate of the latter is available. This figure confirms the empirical observation that sustainable capacity is typically an order of magnitude higher than renewable capacity. Specifically, sustainable capacity (E_s) is a multiple, Q, of renewable capacity (E_r), where α ranges from about 5–45, with a value of 10 most likely. The author has always observed that α, which can be termed the "Sustainability Factor," tends to be high for a hydrothermal reservoir if the host formation is sedimentary. This is to be expected because having intergranular porosity, a porous sedimentary formation would display better heat transfer characteristics than a fractured non-sedimentary formation.□

Wisian et al. [12] concluded from surface heat flow studies of a large number of geothermal fields that the presently installed capacity in most fields is equivalent to no more than ten times the natural heat discharge rate at the surface. Their conclusion at first seems to contradict this entry's assumption that the sustainable capacity is 5–45 times the natural heat discharge rate, 10 times being most likely rather than the maximum. This difference can be explained by the fact that Wisian et al. [12] considered installed plant capacity, which is in general smaller than the maximum sustainable capacity.



Geothermal Power Capacity, Sustainability and Renewability of. Figure 3
Renewable capacity versus sustainable capacity [7]

Finally, the empirical observation that the sustainable capacity of a reservoir is an order of magnitude higher than the renewable capacity implies that, following exploitation, the reservoir is expected to take an order of magnitude higher time span compared to the exploitation period for complete natural replenishment. This supports the earlier observation from reservoir simulation that the depletion effects of power production for 20–30 years would require on the order of 100–300 years to completely disappear.

Estimation of Renewable, Sustainable, and Commercial Capacities

The best tool for quantifying renewable capacity is a numerical simulation model that reproduces the natural physical state of the reservoir. But estimating sustainable and commercial capacities requires not only natural-state modeling but also trial-and-error matching of the actual exploitation history of the reservoir, and forecasting its behavior, using a reservoir simulation model. Estimation of an un-sustained commercial capacity also requires market considerations and economic analysis. Assessment of even renewable capacity may require trial-and-error history matching and forecasting if the recharge rate increases with reservoir pressure decline, which is sometimes the case. Obviously, the effective use of such numerical simulation requires adequate data on the natural state of the reservoir and significant production history. For some fields, renewable and sustainable capacities can be approximated by simple, "lumped-parameter" modeling of the production history. For many fields, data may not be available for numerical simulation or even for relatively simple lumped-parameter modeling. For such situations, approximate formulations to quantify these capacities are presented in Sanyal et al. [34] and are reproduced below.

By definition, Renewable Capacity (E_r) is given by [34]:

$$E_r = R = D_{\text{cond}}, \tag{1}$$

where R is heat recharge rate into the reservoir (primarily convective with a small conductive component) and D_{cond} is total heat discharge from the surface over the thermal anomaly; if the entire heat anomaly on the surface is considered, the convective component of heat

discharge is usually negligible. Ideally, D_{cond} should be estimated from a comprehensive "heat budget" survey of the anomaly including conductive heat loss at the surface, convective heat discharge (through hot springs, fumaroles and geysers) at surface manifestations, and subsurface convective heat loss to regional aquifers.

Strictly speaking, the small rate of background (regional) heat flow should be subtracted from the estimates of renewable capacity above and sustainable capacity as presented below [34]. However, given the approximate nature of such estimation, this correction is unnecessary in most situations.

Sustainable capacity (E_s), considering both heat mining and heat recharge, is given as [34]:

$$E_s = \left\{ \left(\frac{C_v}{KL} \right) rhd \left(\frac{A_{res}}{A} \right) + 1 \right\} D_{cond}, \tag{2}$$

where C_v is volumetric specific heat of fluid-filled rock, K is thermal conductivity of the overburden, L is plant life, r is heat energy recovery factor, h is reservoir thickness, d is depth to the top of the reservoir, A_{res} is reservoir area, and A is the area of the entire thermal anomaly.

A conservative definition of commercial capacity (E_c) would require that $E_c > E_s$ initially, but eventually falls below E_s, such that the total energy recovered over the plant life is same as that would be for production at the sustainable level. With this definition, and "harmonic decline" in well productivity, it can be shown [34]:

$$E_c = \frac{E_s L D_i}{\ln(1 + D_i L)}, \tag{3}$$

where D_i is initial decline rate in well productivity. E_c can be considerably higher than E_s, depending on economic factors. The higher the margin by which E_c exceeds E_s, the higher is D_i.

An actual example, that of the Beowawe geothermal field in the State of Nevada, United States, can be considered. For this field,

$$\left(\frac{A_{res}}{A} \right) \approx 0.1$$

$$d = 900\,\text{m}, \text{and } h = 1,500\,\text{m}$$

From Butler et al. [10], for this field, $R = 1.3$ MWe $\approx D_{cond}$ (ignoring background heat flow).

Therefore, Renewable Capacity = 1.3 MWe

Typical values of the other parameters are: C_v = 2,700 kJ/m^3/°C, K = 3.1 W/m/°C, L = 30 years and r = 0.1.

Therefore, from Eq. 2, Sustainable Capacity ≈18 MWe (ignoring background heat flow).

Most likely reserves for this field, from Klein et al. [35] = 58 MWe.

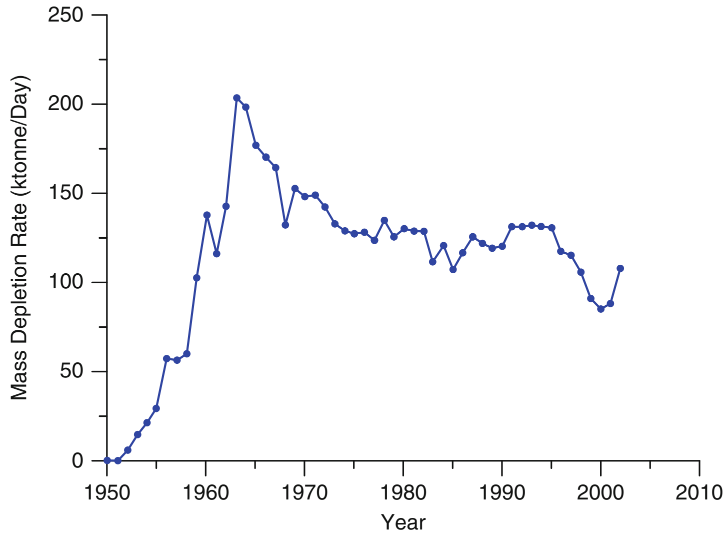
Therefore, commercial capacity would fall somewhere between 18 and 58 MWe, depending on the economic factors. For example, if no make-up well drilling is contemplated and an initial harmonic productivity decline rate of 10% is economically acceptable, from Eq. 3, E_c = 40 MWe.

The above discussion shows that the renewable development level for the Beowawe field is only 1.3 MWe, which is entirely uneconomic. While a sustainable capacity of 18 MWe is commercial, a capacity of 40 MWe may even be more attractive economically, and yet would cause no further cumulative energy withdrawal from the reservoir over a 20–30-year project life, and consequently, the reservoir should still be replenished naturally, in a 100–300-year time frame. It should be noted that a plant capacity of 13 MWe has already been sustained in this field over the past 2 decades.

An Illustrative Case History

This is a case history of estimating renewable and sustainable capacities of a geothermal field (at Wairakei, New Zealand) from its production history using a simple "lumped-parameter" model. The Wairakei field presents a good case history because: (a) it has more than 50 years of production history, longer than that of any other liquid-dominated field in the world; (b) it offers an extensive database that is publicly available (for example, Clotworthy [36]); and (c) since the average temperature of this reservoir has not declined significantly over its long production history, its pressure behavior can be reasonably modeled by considering material balance only (rather than coupled material-and-energy balance).

Numerical simulation and heat flow studies of this field have shown the steady-state recharge rate in the natural state to be about 31 kt/day; in other words, the minimum renewable depletion capacity (E_r) is 31 kt/day. Figure 4 presents a plot of the mass depletion rate (m), defined as production rate minus injection rate,



Geothermal Power Capacity, Sustainability and Renewability of. Figure 4
Mass depletion history [7]

versus time at this field. As of 1956 (2,000 days from the initiation of production in 1950), the reservoir pressure in the deep liquid zone in the Western Borefield (the portion of the field eventually most exploited) was about 52 bar-a, and negligible production had taken place before that time. From material balance consideration, it can be shown [7] that reservoir pressure (p) is given as:

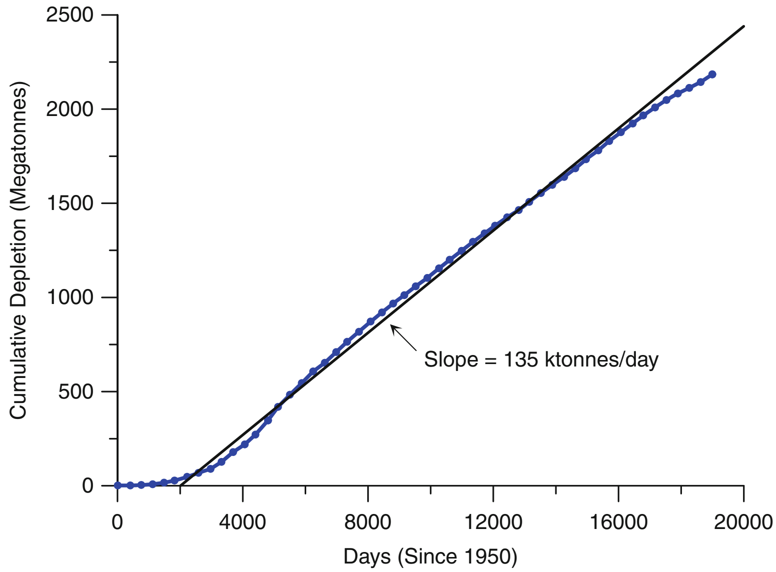
$$p = 52.0 - \frac{(m-31)}{r}\left[1 - e^{-\frac{r}{s}(t-2000)}\right], \tag{4}$$

where m is assumed constant with time (t, days), r is a recharge coefficient (kt/day/bar), and s is a reservoir storage coefficient (kt/bar).

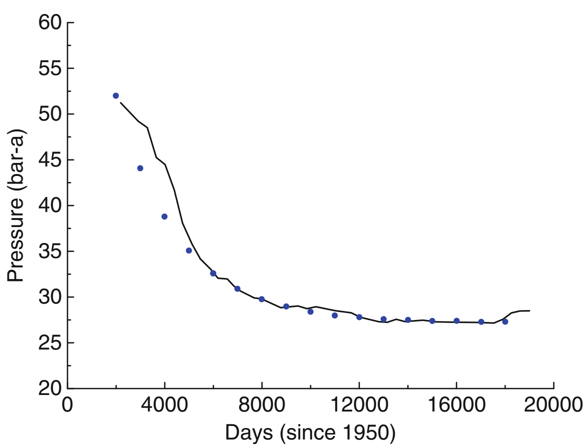
Figure 5 shows the cumulative depletion history of the field. Between 2,000 days and the present, a reasonably linear trend can be defined with a slope of 135 kt/day. Therefore, one can approximate a constant value of m after 2,000 days as 135 kt/day. The unknowns r and s in Eq. 4 can be estimated by trial-and-error; Fig. 6 shows the best fit the author obtained between the observed pressure (continuous curve) at the deep liquid zone of the Western Borefield and the computed pressures (solid circles) as a function of time; this fit required an s value of 11,000 kt/bar and an r value of 4.2 kt/day/bar. The fit in Fig. 6 is good between 5,000 and 18,000 days, a span of 36 years; a look at Fig. 5 shows that the poor match before and after this period is to be expected as the depletion trend had deviated significantly from the linear in the very early and very recent periods.

The overall recharge rate at any time is the sum of the steady-state recharge rate (m_{sr}) and the pressure-dependent component of recharge rate (m_r) [7]. Using the r and s values derived above, the historical rate of recharge at Wairakei has been estimated as shown in Fig. 7. Overall, fluid recharge at Wairakei to date appears to have been generally hot because negligible overall cooling of the reservoir has been noted in 50 years, and recharge has steadily increased in response to pressure drawdown (Fig. 7). For this reason, the renewable level of depletion of this reservoir has become steadily higher than the steady-state depletion rate of 31 kt/day derived from natural-state modeling. In fact, the recharge rate by 17,000 days has nearly equaled the depletion rate; if the entire recharge here indeed represents hot fluid entry from depth, then a depletion level of 135 kt/day, rather than 31, can be considered renewable.

Now, what is the sustainable depletion capacity (E_s) of this reservoir? If the minimum static reservoir pressure at which wells in this field can still flow commercially can be estimated, then one can calculate E_s for any assumed project life. Wellbore simulation for wells producing from the deep liquid zone at Wairakei indicates



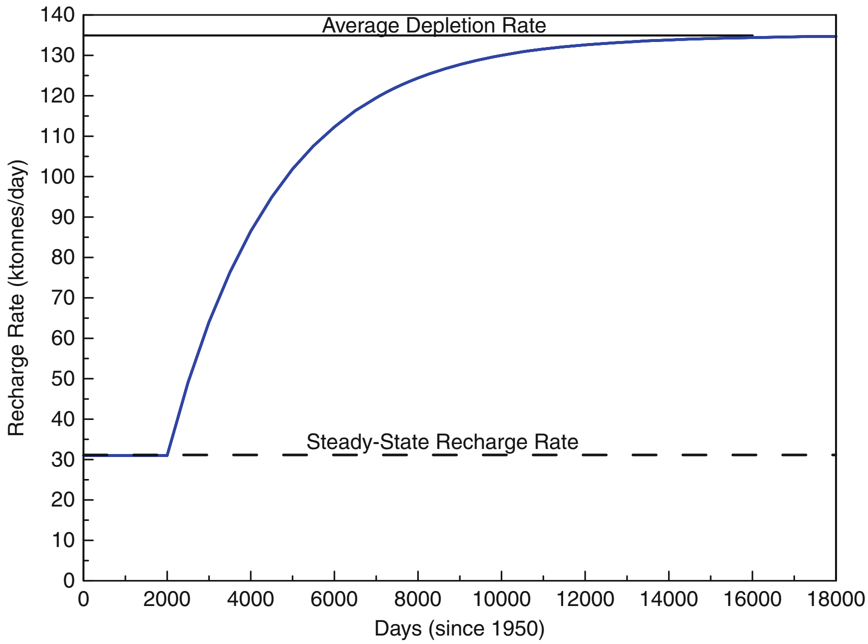
Geothermal Power Capacity, Sustainability and Renewability of. Figure 5
Cumulative depletion history [7]



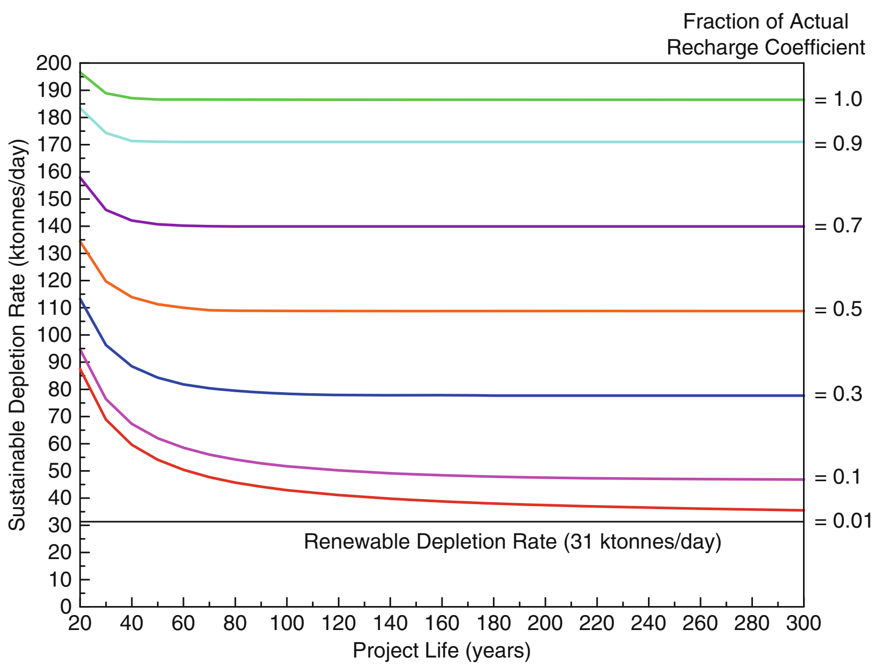
Geothermal Power Capacity, Sustainability and Renewability of. Figure 6
Observed and computed liquid pressures, western borefield [7]

this minimum pressure value to be about 15 bar-a. Therefore, one can calculate the sustainable capacity, assuming only hot recharge, for any assumed project life from Eq. 4.

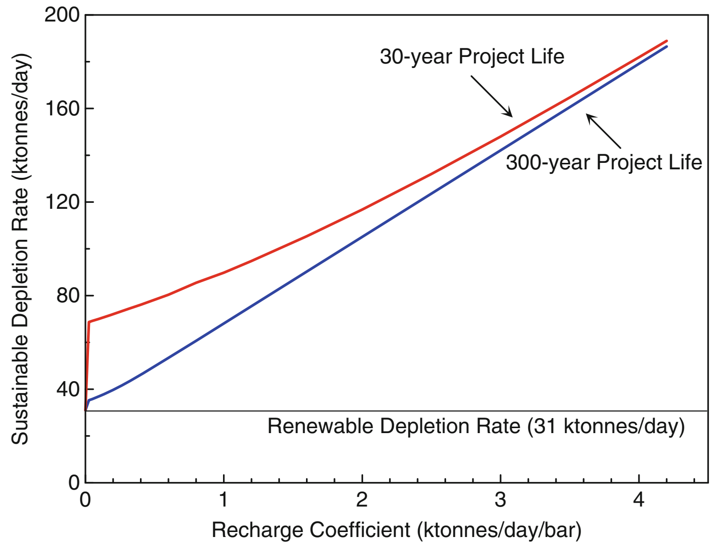
The above equation gives very similar values of E_s for a 30-year project life or a 300-year project life, 188.8 and 186.5 kt/day, respectively. This relative insensitivity of E_s to project life is due to the very high recharge coefficient and the apparent preponderance to date of hot rather than cool recharge at Wairakei; this latter fact is also supported by numerical simulation. Since recharge rate in most fields is lower than at Wairakei, an assessment was made of how E_s would have changed as a function of project life if the recharge coefficient at Wairakei were smaller. Figure 8 shows the calculated E_s value versus project life for a range of hypothetical recharge coefficients expressed as fractions of the actual recharge coefficient at Wairakei. Figure 8 shows that as the recharge coefficient becomes smaller, so does sustainability and the latter becomes more sensitive to project life. Figure 9 shows the same data as in Fig. 8 represented as sustainable capacity versus recharge coefficient for project lives of both 30 and 300 years. This figure illustrates that the difference between renewable and sustainable capacities for 30- and 300-year project lives becomes less as recharge coefficient increases, for Wairakei this difference (corresponding to an r of 4.2 kt/day) being negligible.



Geothermal Power Capacity, Sustainability and Renewability of. Figure 7
Recharge rate versus time, Wairakei field [7]



Geothermal Power Capacity, Sustainability and Renewability of. Figure 8
Sustainable depletion rate versus project life, Wairakei field [7]



Geothermal Power Capacity, Sustainability and Renewability of. Figure 9
Sustainable capacity versus recharge coefficient [7]

Finally, it should be noted that sustainability factor (α□), as defined before, for Wairakei is 188.8/31, or 6.1. Why is this value of sustainability factor at the low end of the range of 5–45 mentioned earlier? The reason is that until recently, there was no injection in this field. Therefore, the above analysis is based on depletion being equal to production. If injection is practiced, the effective depletion rate will be lower than production rate, and therefore, a higher production capacity can be sustained. For example, if 50% of the produced fluid were injected, the sustainable production rate would be double the sustainable depletion rate (188.8 kt/day), that is, 377.6 kt/day, assuming the recharge to be predominately hot. Therefore, the sustainability factor would be 377.6/31 or 12.2; this sustainable production capacity is an order of magnitude higher than the renewable capacity of 31 kt/day.

Future Directions

The debate over renewability and sustainability of power capacity of a geothermal reservoir still continues for conventional geothermal systems, which are naturally occurring subsurface porous or fractured systems that can be tapped for production by drilling wells. However, in the last decade, considerable hopes have been raised of tapping geothermal energy from enhanced geothermal systems ("EGS") [37]. These are hot subsurface systems with porosity or fracture capacity too low to allow commercial production but can be enhanced by pervasive hydraulic fracturing to enable significant fluid injection and production. In an EGS project, heat is recovered from the artificial reservoir by injecting cool water through a set of wells while producing heated water from another set of wells. Such systems have not yet proven commercial, but research and development toward commercial tapping of EGS systems continue.

If EGS systems can be exploited commercially, the energy reserves in such systems in the USA would be two orders of magnitude larger than the energy contained in the conventional geothermal systems [38]. Even in countries where conventional geothermal systems do not exist, EGS developments would be the theoretically possible, because anywhere on earth adequately hot rock bodies can be reached by drilling wells deep enough and creating an artificial reservoir by hydraulic fracturing of rock.

Renewability and sustainability of EGS systems have not received much attention yet, but in the future, this issue will become important if EGS exploitation

becomes a commercial reality. The one major difference between renewability and sustainability of conventional systems and those of an EGS is that an EGS reservoir does not receive natural convective heat recharge; all heat recharge to an EGS reservoir would be conductive which, as discussed earlier, is relatively minor. Furthermore, an abandoned EGS project would not be fully replenished in 100–300 years as expected for conventional systems because of this lack of convective heat recharge.

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Geothermal Power Conversion Technology

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Article Outline

Glossary

Ambient Natural condition of the environment at any given time.

Baseload The lowest level of power production needs during a season or year.

Baseload plants Electricity-generating units that are operated to meet the constant or minimum load on the system. The cost of energy from such units is usually the lowest available to the system.

Binary-cycle power station A geothermal electricity-generating station employing a closed-loop heat exchange system in which the heat of the geothermal fluid (the "primary fluid") is transferred to a different fluid ("motive," "secondary," or "working" fluid), which is thereby vaporized and used to drive a turbine/generator set.

Bi-phase expander A bi-phase expander or bi-phase turbine is a device that produces power by utilizing the energy of two-phase (liquid/vapor) streams. The total energy produced by the brine and the separated steam (in a reduced condition), is expected to be higher than that of the steam turbine alone.

Brine A geothermal solution containing appreciable amounts of sodium chloride or other salts.

Capacity factor A percentage that tells how much of a power station's capacity is used over time. For example, typical station capacity factors range as high as 80% for geothermal and 70% for cogeneration.

Capacity, installed (or Nameplate) The total manufacturer-rated capacities of equipment such as turbines, generators, condensers, transformers, and other system components.

Capacity The amount of electric power delivered or required for which a generator, turbine, transformer, transmission circuit, station, or system is rated by the manufacturer.

Carbon dioxide A colorless, odorless, nonpoisonous gas that is a normal part of the air. Carbon dioxide, also called CO_2, is exhaled by humans and animals and is absorbed by green growing things and by the sea.

CHP Combined heat and power

Condensate Liquid formed by condensation of vapor.

Cooling tower A structure in which process heat is removed to the atmosphere.

Cost The amount paid to acquire resources, such as station and equipment, fuel, or labor services.

Demand The level at which electricity or natural gas is delivered to users at a given point in time. Electric demand is expressed in kilowatts.

Direct use Use of geothermal heat without first converting it to electricity, such as for space heating and cooling, food preparation, industrial processes, etc.

Dispatch The operating control of an integrated electric system to assign generation to specific generating stations and other sources of supply to effect the most reliable and economical supply as the total of the significant area loads rise or fall. Control operations and maintenance of high-voltage lines, substations and equipment, including administration of safety procedures. Operate the interconnection. Schedule energy transactions with other interconnected electric utilities.

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Drift eliminator Drift eliminators reduce the amount of drift in the exiting air flow. Drift droplets can be reduced to less than 0.1% by effective use of an eliminator.

Drift Drift droplets are any water droplets and dissolved and suspended solids that are entrained in the air and emitted from the cooling tower stack.

Dry steam Very hot steam that does not occur with liquid.

Efficiency The ratio of the useful energy delivered by a dynamic system (such as a machine, engine, or motor) to the energy supplied to it over the same period or cycle of operation. The ratio is usually determined under specific test conditions.

Effluent Treated wastewater.

EGS Engineered geothermal systems

Emissions standard The maximum amount of a pollutant legally permitted to be discharged from a single source.

Energy efficiency Refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption (reported in megawatthours), often without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technically more advanced equipment to produce the same level of end-use services (lighting, heating, and motor drive) with less electricity. Examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems.

Energy source The primary source that provides the power that is converted to electricity through chemical, mechanical, or other means. Energy sources include coal, petroleum and petroleum products, gas, water, uranium, wind, sunlight, and geothermal and other sources.

Energy The capacity for doing work as measured by the capability of doing work (potential energy) or the conversion of this capability to motion (kinetic energy). Energy has several forms, some of which are easily convertible and can be changed to another form useful for work. Most of the world's convertible energy comes from fossil fuels that are burned to produce heat that is then used as a transfer medium to mechanical or other means in order to accomplish tasks. Electrical energy is usually measured in kilowatt-hours, while heat energy is usually measured in British thermal units.

Facility An existing or planned location or site at which prime movers, electric generators, and/or equipment for converting heat into electric energy are situated, or will be situated. A facility may contain more than one generator of either the same or different prime mover type.

Fault A fracture or fracture zone in the Earth's crust along which slippage of adjacent Earth material has occurred at some time.

Flash steam Steam produced when the pressure on a geothermal liquid is reduced. Also called flashing.

Flash tank Vessel in which the geothermal water or brine is flashed into steam by pressure reduction.

Fly ash Particulate matter from coal ash in which the particle diameter is less than 1×10^{-4} m. This is removed from the flue gas using flue gas particulate collectors such as fabric filters and electrostatic precipitators.

Generation (electricity) The process of producing electric energy by transforming other forms of energy also, the amount of electric energy produced, expressed in watt-hours (Wh).

Generator A machine that converts mechanical energy into electrical energy.

Geology Study of the planet Earth, its composition, structure, natural processes, and history.

Geothermal combined cycle An electricity-generating technology in which electricity is produced from the steam exiting from one or more steam turbines at above atmospheric pressure. The exiting steam routed to the evaporator of an ORC station producing electricity. This process reduces the impact of non-condensable gases in the geothermal steam and eliminates the power consumption of the vacuum pumps or ejectors (updated using various sources).

Geothermal energy Natural heat from within the Earth, captured for production of electric power, space (geofluid) heating or industrial steam.

Geothermal fluid Can be steam, water, brine or a mixture of two, may contain noncondensable gases (CO_2, H_2S) and in case of brine, appreciable amounts of sodium chloride, carbonates, and silica.

Geothermal heat pumps Devices that take advantage of the relatively constant temperature of the Earth's interior, using it as a source and sink of heat for both heating and cooling. When cooling, heat is extracted from the space and dissipated into the Earth when heating, heat is extracted from the Earth and pumped into the space.

Geothermal power station A power station in which the prime movers are turbines operated either by steam or organic fluids vapor. The steam is either natural or produced from flashing of hot water. The organic fluid vapor is produced by boiling of the organic fluid using geothermal steam or water. The natural steam and water derive energy from heat found in rocks or fluids at various depths beneath the surface of the Earth. The energy is extracted by drilling and/or pumping. It includes all the surface facilities including the geothermal fluid gathering and treatment system, but does not include the geothermal wells and pumps.

Geothermal steam Steam drawn from deep within the Earth.

Geothermal Of or relating to the Earth's interior heat.

Geyser A spring mat that shoots jets of hot water and steam into the air.

Geysers, The A large geothermal steam field located approximately 75 miles (121 km) north of the city of San Francisco, California.

Gigawatt (GW) One billion watts.

Gigawatt-hour (GWh) One billion watt-hours.

Greenhouse effect The increasing mean global surface temperature of the Earth caused by gases in the atmosphere (including carbon dioxide, methane, nitrous oxide, ozone, and chlorofluorocarbon). The greenhouse effect allows solar radiation to penetrate but absorbs the infrared radiation returning to space.

Grid The layout of an electrical distribution system.

Heat exchanger A device for transferring thermal energy from one fluid to another.

Hot dry rock (HDR) A geothermal resource created with impermeable, subsurface hot rock structures, typically granite rock below the Earth's surface. The resource is being investigated as a source of energy production.

Hybrid geothermal cycles Cycles in which there are in series or in parallel a steam Rankine cycle and an Organic Rankine cycle.

Hybrid geothermal power stations Stations in which the geothermal heat is supplemented by another heat source.

Hydrothermal resource Underground systems of hot water and/or steam.

Injection The process of returning spent geothermal fluids to the subsurface. Sometimes referred to as reinjection.

Kilowatt (kW) One thousand watts.

Kilowatt-hour (kWh) One thousand watt-hours.

Known geothermal resource area A region identified by the US Geological Survey as containing geothermal resources.

Leaching The removal of readily soluble components, such as chlorides, sulfates, organic matter, and carbonates, from soil by percolating water. The remaining upper layer of leached soil becomes increasingly acidic and deficient in plant nutrients.

Load (electric) The amount of electric power delivered or required at any specific point or points on a system. The requirement originates at the energy-consuming equipment of the consumers.

Magma The molten rock and elements that lie below the Earth's crust. The heat energy can approach 550°C and is generated directly from a shallow molten magma resource and stored in adjacent rock structures. To extract energy from magma resources requires drilling near or directly into a magma chamber and circulating water down the well in a convection-type system.

Megawatt (MW) One thousand kilowatts (1,000 kW) or one million watts (1,000,000 W).

Megawatt-hour (MWh) One million watt-hours.

Muffler It is a device for reducing noise of high-speed steam flow in emergency relief of high-pressure steam from the production well (PW) in the power station. In geothermal applications it not only acts as a silencer but also performs safety and environmental duties. This is because of the high temperature and high salinity of the steam and brine that is released to the atmosphere in case of turbine trip-off or system emergency shutdown.

Noncondensable gases (NCG) Gases present in the steam or dissolved in the brine and liberated in the flash process.

Ormat energy converter (OEC) A unit using Ormat's Organic Rankine Cycle technology, which converts geothermal heat to electric power.

ORC power station A power station operating according to the ORC process.

Organic Rankine cycle (ORC) A Rankine cycle using an organic fluid (updated using various sources).

Outage The period during which a generating unit, transmission line, or other facility is out of service.

Particulate matter (PM) Unburned fuel particles that form smoke or soot and stick to lung tissue when inhaled. A chief component of exhaust emissions from heavy-duty diesel engines

pH The term pH is a measure of acidity or alkalinity and ranges from 0 to 14. A pH measurement of 7 is regarded as neutral. Measurements below 7 indicate increased acidity, while those above indicate increased alkalinity.

Point source A stationary location or fixed facility from which pollutants are discharged.

Power plant A power station.

Power station A facility at which prime movers electric generators, and auxiliary equipment are located, for converting mechanical, chemical, and/or nuclear energy into electric energy. A station may contain more than one type of prime mover.

Power Electricity for use as energy.

Precipitation Precipitation is the formation of a solid in a solution. The solid formed is called the precipitate, and the liquid remaining above the solid is called the supernate.

Price The amount of money or consideration-in-kind for which a service is bought, sold, or offered for sale.

Purifier Vessel at the turbine in which fine droplets are separated from the vapor.

Regulation The governmental function of controlling or directing economic entities through the process of rulemaking and adjudication.

Reliability Electric system reliability has two components adequacy and security. Adequacy is the ability of the electric system to supply to aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system facilities. Security is the ability of the electric system to withstand sudden disturbances, such as electric short circuits or unanticipated loss of system facilities. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on consumer services.

Renewable energy Resources that constantly renew themselves or that are regarded as practically inexhaustible. These include solar, wind, geothermal, hydro, and wood. Although particular geothermal formations can be depleted, the natural heat in the Earth is a virtually inexhaustible reserve of potential energy. Renewable resources also include some experimental or less-developed sources such as tidal power, sea currents, and ocean thermal gradients.

Renewable resources Natural but flow-limited resources that can be replenished. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Some (such as geothermal and biomass) may be stock-limited in that stocks are depleted by use, but on a time scale of decades, or perhaps centuries, they can probably be replenished. Renewable energy resources include: biomass, hydro, geothermal, solar, and wind. In the future, they could also include the use of ocean thermal, wave, and tidal action technologies. Utility renewable resource applications include bulk electricity generation, on-site electricity generation, distributed electricity generation, non-grid-connected generation, and demand-reduction (energy efficiency) technologies.

Reservoir A natural underground container of liquids, such as water or steam (or, in the petroleum context, oil or gas).

Revenue The total amount of money received by a firm from sales of its products and/or services, gains from the sales or exchange of assets, interest and dividends earned on investments, and other increases in the owner's equity except those arising from capital adjustments.

Saturation Saturation is the point at which a solution of a substance can dissolve no more of that substance and additional amounts of it will appear as a precipitate. This point of maximum concentration, the saturation point, depends on the temperature of the liquid as well as the chemical nature of the substances involved.

Scaling Scaling is formation of a deposit layer (scale) on a solid surface, i.e., evaporators, pipes, etc.

Screw expander The screw expander is the reverse usage of a screw compressor consisting of two helical rotating wheels compressing gas in between them. When high-pressure gas is introduced to the compressor exit, it expands forcing the screw wheels to rotate backward and produce power.

Scrubber Equipment used to remove sulfur oxides or hydrogen sulfide from the geothermal fluid before discharge to the atmosphere. Chemicals, such as lime, are used as the scrubbing media. The scrubber is also used when fresh water is applied to saline-contaminated steam. The scrubber reduces the steam salinity before it enters the turbine.

Separator A vessel at the wellhead where steam is separated from water or brine. Mostly of centrifugal type.

Solubility Solubility is the property of a solid, liquid, or gaseous chemical substance called solute to dissolve in a liquid solvent to form a homogeneous solution of the solute in the solvent. The solubility of a substance fundamentally depends on the used solvent as well as on temperature and pressure.

Stability The property of a system or element by virtue of which its output will ultimately attain a steady state. The amount of power that can be transferred from one machine to another following a disturbance. The stability of a power system is its ability to develop restoring forces equal to or greater than the disturbing forces so as to maintain a state of equilibrium.

Steam Rankine cycle A Rankine cycle in which water (in liquid and vapor phase) is the motive fluid (updated using various sources).

System (electric) Physically connected generation, transmission, and distribution facilities operated as an integrated unit under one central management, or operating supervision.

System A combination of equipment and/or controls, accessories, interconnecting means, and terminal elements by which energy is transformed to perform a specific function, such as climate control, service water heating, or lighting.

Thermal pollution A reduction in water quality caused by increasing its temperature, often due to disposal of waste heat from industrial, power generation processes, or urban impervious surfaces (such as parking lots). Thermally polluted water can harm the environment because plants and animals may have difficulty adapting to it.

Transmission The movement or transfer of electric energy over an interconnected group of lines and associated equipment between points of supply and points at which it is transformed for delivery to consumers, or is delivered to other electric systems. Transmission is considered to end when the energy is transformed for distribution to the consumer.

Turbine generator A device that uses steam, organic vapor, heated gases, water flow or wind to cause spinning motion that activates electromagnetic forces and generates electricity (updated using various sources).

Turbine A machine for generating rotary mechanical power from the energy of expansion of a stream of fluid (such as water, steam, organic vapor, or hot gas). Turbines convert the kinetic energy of fluids to mechanical energy through the principles of impulse and reaction, or a mixture of the two (updated using various sources).

Utility A regulated entity which exhibits the characteristics of a natural monopoly. For the purposes of electric industry restructuring, "utility" refers to the regulated, vertically integrated electric company. "Transmission utility" refers to the regulated owner/operator of the transmission system only. "Distribution utility" refers to the regulated owner/operator of the distribution system which serves retail customers.

Vapor(or steam)-dominated resources A geothermal reservoir system in which subsurface pressures are controlled by vapor rather than liquid and most of the flow is steam.

Water-dominated resource A resource where the major part of the mass flow is water or brine.

Watt The electrical unit of power. The rate of energy transfer equivalent to 1 A flowing under a pressure of 1 V at unity power factor.

Watt-hour (Wh) An electrical energy unit of measure equal to 1 W of power supplied to, or taken from, an electric circuit steadily for 1 h.

Definition of Geothermal Power Conversion Technology

Geothermal Power Conversion Technology refers to techniques used for the conversion of the heat content of geothermal fluid into mechanical power in order to drive a generator and produce electric power.

The first 1/4 HP reciprocating steam engine unit was installed in 1904 by Prince Piero Ginori Conti in the Larderello geothermal field in Italy. Prior to World War II, there were already 136.8 MW of capacity installed in Larderello area. After the war more wells were drilled and modern power stations were installed in the area. As of December 2009, the current operator, ENEL, had 842 MW of installed geothermal power capacity in the Tuscany area.

The first steam engine–driven generator of 35 kW was installed in the USA in 1921 in The Geysers of California. Only in the 1950s, the region was further developed and today 900 MW are produced in this area.

In Japan, surveys began in 1918 with the first experimental generator installed on the island of Kyushu in 1925. Russia followed in 1941 in Kamchatka. Extensive exploration and installations were performed in the 1950s in Japan, Russia, New Zealand, Iceland, Kenya, the Azores Islands off of Portugal and The Philippines.

In the 1980s, Organic Rankine cycle power conversion was applied to geothermal resources of lower enthalpy and widened the range of exploitable resources to lower temperatures.

Today about 10,700 MW are in operation in 24 countries.

Introduction

Power conversion is the least risky part of a geothermal project. Generally it consists of a straight forward engineering design with work executed by experienced manufacturers, engineering firms and contractors.

The risks and challenges are related to exploration, drilling and managing the resource (see preceding entries). Optimization depends on the choice of adaptation of the power station configuration to the resources available (see section on "Choosing the Energy Conversion Systems").

There are four basic types of resources:

- Vapor dominated
- Water dominated
- Pressurized water
- EGS engineered geothermal systems where water has to be pumped into the hot rock fissures and cavities. These systems are in early development and demonstration phases

Four energy conversion systems for geothermal resources are in commercial operation:

- Steam Rankine Cycle for Dry Steam
- Steam Rankine Cycle for double or triple flash
- Organic Rankine Cycle in Binary stations for moderate resource temperature
- Combined steam and Organic Rankin Cycle for resource of high temperature and non condensable gases.

To widen the range of resources suitable for power generation beyond dry-steam and flashed steam stations. Of the over 10,000 MW of geothermal stations installed worldwide, most use steam turbines operating on dry steam or steam produced by single or double flash by the end of 2009. About 1,000 MW use ORC or geothermal combined cycles.

Operational experience has confirmed the advantages of ORC power stations, not only for low-enthalpy water-dominated resources, but also certain high enthalpy ones where the brine is aggressive or the fluid contains a high percentage of noncondensable gas. The higher installation cost of these systems is often justified by environmental and long-term resource management considerations.

This entry is not a design manual for a power station (for detailed calculations, references are given), a history (see preceding entries), or an inventory of existing geothermal stations or a list of future projects. These subjects are dealt with in the following entries.

This is a review of power conversion configuration based on the author's 30 years' experience of implementing various power systems.

What is attempted here is to give a comprehensive picture of adapting the power conversion to various geothermal resources optimizing the output, minimizing the negative implications, and enhancing the sustainability. The objective is to enable the reader to assess the full picture while relying on experienced consultants and vendors in each discipline.

The most updated and comprehensive data on geothermal energy covering both the resource and power conversion systems can be found in: DiPippo R, "Geothermal Power Plants," 2nd edn. Elsevier and Glassley W, "Geothermal Energy," CRC Press.

Further reading on geothermal energy can be found on the Department of Energy internet site at:

http://www.energy.gov/energysources/index.htm
http://www.energy.gov/energysources/geothermal.htm
http://www1.eere.energy.gov/geothermal/history.html

The MIT publication on the future of geothermal energy can be found at http://geothermal.inel.gov/publications/future_of_geothermal_energy.pdf

The IEA-GIA Website at http://www.iea-gia.org/

The Geothermal Research Council at http://www.geothermal.org/

The Geothermal Energy Association at http://www.geo-energy.org/

Geothermal Project Design and Implementation

General

A geothermal project is composed of two elements very different in nature and risk: a straightforward conversion system, converting heat into electricity, and the heat supply, i.e., the geothermal resource with attributes similar to oil and gas fields.

Using the terminology of the oil industry a geothermal power project is an integration of "upstream" with "downstream," hence its particularity. The "upstream" is handled in the other entries. The "downstream" covers the surface equipment.

The project risk is associated with the primary fuel development and it rests with the Investor (Independent Power Producer (IPP) or Utility) rather than with a supplier of fuel.

The aggregate risk in a geothermal project, in a macro sense is different from fossil fuel plant in that the fuel supply risk and investment are mostly up front. As it is site and location specific, it cannot be monetized and the resource supply or quality cannot be substituted, as fossil fuel can, by finding another source from the market.

An important advantage of geothermal power stations is that after the initial investment is made. The power is supplied at a predictable cost unaffected by price fluctuations.

Overview of Geothermal Station Implementation

Development of a geothermal project typically proceeds in two parallel paths, technical operations, i.e., "work on the ground" and commercial/legal procedures, as shown in the scheme in Table 1.

The process starts with identifying a potential site based on desktop studies and preliminary fieldwork covering known geological data and surface manifestations, indicating the existence of an underground geothermal system (hot springs and fumaroles). Results of previous exploration by other parties (other geothermal developers, state agencies, mining companies, oil and gas companies, etc.), if such data exists. This information is then combined with business information, including the need for power in that area, the expected power prices, the existing and missing infrastructure, namely, a transmission grid and road, environmental/permitting constraints, other business, financial and political risks, etc. A "go/no-go" decision is taken. If a "go" decision is taken, the next steps are as follows:

Obtaining a geothermal concession (when applicable): Since most countries view geothermal resources as a strategic resource owned by the state, obtaining a state geothermal concession is the first step to geothermal development. This concession is typically awarded by winning a state bid. In the USA, the Federal Steam Act basically assigned geothermal rights to the surface owner, be that the Federal Government Bureau of Land and Management, the state, a private owner, etc.

Obtaining a land position: This is done most typically through geothermal leasing, but sometimes also through land acquisition or other business structures.

Initial nonintrusive exploration: typically including basic geology, geochemical sampling, and geophysical surveys, e.g., gravity, magnetic and electric. This phase may require some permitting work, depending on the type of fieldwork and surveys plans and the local regulations.

Permitting for exploration drilling: Exploration drilling, typically starting with shallow temperature gradient holes, moving to medium depth and slim

Geothermal Power Conversion Technology. Table 1 Schematic planning of geothermal project implementation

	Prior to kick-off	Year 1				Year 2				Year 3				Year 4				Year 5				Year 6- onwards			
Activity	**Varies**	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Resource Identification and Acquisition	■																								
Locating potential sites	■																								
Obtaining surface and subsurface rights	■																								
Power Purchase Agreement (if developer)	■																								
Exploration and Resource Confirmation		■	■	■	■	■	■	■	■	■	■	■													
Non-intrusive exploration		■	■	■	■	■																			
Drilling permitting					■	■	■																		
Temperature gradient drilling							■	■																	
Slim-hole drilling and feasibility									■	■															
Initial full-size deep drilling and resource confirmation											■	■													
Engineering, Procurement, Construction and Field Development													■	■	■	■	■	■	■	■					
Plant design													■												
Plant permitting, including well-field and transmission line													■	■	■	■	■								
Drilling production and injection wells																■	■	■	■	■					
Equipment purchasing and manufacturing													■	■	■	■	■								
Power plant construction																		■	■	■					
Gathering system construction																			■	■					
Transmission line and utility interconnection													■	■	■	■	■	■	■	■					
Commissioning and Start-Up																					■				
Commercial operation																						■	■	■	■

holes and eventually two to three full diameter deep production and injection wells.

Permitting for roads, power lines, power stations, and its operation.

Long-term multi-well flow testing: In order to accurately determine the average temperature and flow, build a reservoir model and estimate the size of the reservoir and the potential electrical generation.

Technical and economical feasibility and final "go/no-go" decision.

Field testing and initial exploration of the site enables the understanding and establishing of the site potential and drawing station layout, initial heat, mass balance and required investment.

This will allow the commercial and legal part to proceed, typically leading to signing of a long-term Power Purchase/Sales Agreement with a local utility.

Although station design will already start during the period of legal and financial negotiations, the completion of design and manufacturing will not commence before the resource is appraised and sale of electricity secured by, or for a utility. At this stage, an NTP (Notice to proceed) will be issued to the engineering, procurement, and construction (EPC) contractor and all technical operations released. The steps are as follows:

Station design:

Obtaining all necessary station permits, including the well-field and transmission line.

Completion of well-field development and equipment manufacturing.

While equipment is being manufactured, on-site operations continue including wellhead, piping, interfaces to transmission lines, roads, buildings, power house, control room, etc. They are marked as:

Gathering system and station construction.

Transmission and interaction.

Both actions, completion of manufacturing and on-site construction, end approximately 4 to 5 years from obtaining land position and kick-off of initial exploration. The actual timeframe can be as short as 2–3 years or as long as 10 years, depending primarily on the existence of historical exploration data, the complexity and pace of permitting and logistical constraints.

Power Station Costs

Essentially, the costs of a geothermal power station are highly dependent on the resource. Most of the variation in costs is experienced during the drilling phase where initial exploration holes will define the resource, its temperature, flow rates and chemical and mineral content for which assumptions can be made regarding the cost of managing the resource over time.

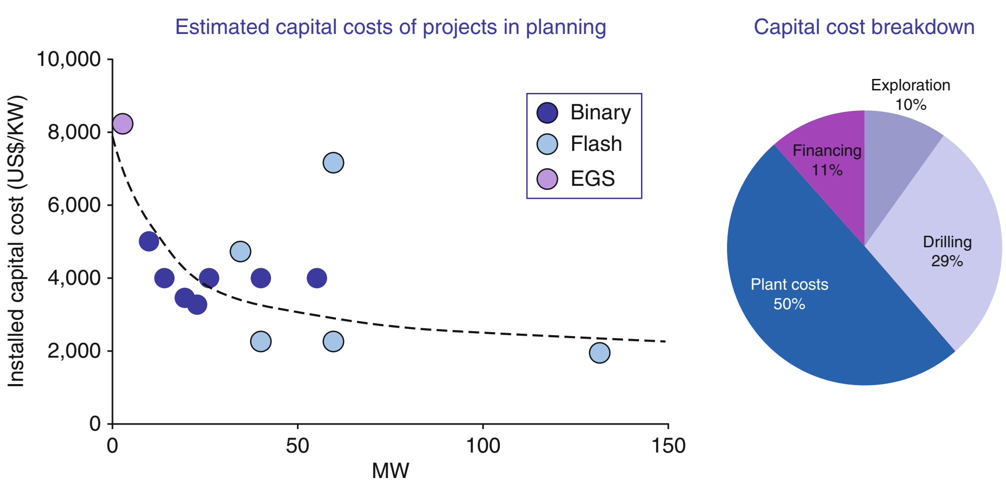
Overall costs in 2010 US dollars range between US$3,000 and US$5,500 per installed kilowatt depending mainly on the quality of the resource (temperature, geothermal fluid chemistry) which compels the conversion technology (binary, flash, steam). This leads to electricity prices in the range of about US$70–US$100 per megawatt-hour.

Cost Estimates for Megawatt-Hour (MWh) Recent estimates from studies on the costs of developing geothermal power stations provide a range for where actual costs may fall. In September 2008, The US Department of Energy provided a broad range of US $63– US$102 per MWh, assuming resource incentives, such as the Federal Production Tax Credit (US DOE 2008 [1]). Several recent estimates put costs within this range, including the California Energy Commission (CEC 2007 [2]), Emerging Energy Research (EER 2009 [3]) and Glacier Partners (Glacier Partners 2009 [4]), which produce estimates between US$72 and US $100 per MWh. Further evidence for the cost of power comes from recent contracts approved by the Public Utility Commission of Nevada (PUCN [5]) in July 2010 and released to the public ranged between US $86 and US$98 per MWh with resource incentives assumed in the contract price (Source: PUCN 2010 [5]). Internationally, prices may be lower due to economies of scale, but not significantly. The International Energy Agency (IEA) backs this up with a 2010 article that describes costs for new generation is in some countries (such as New Zealand) as highly competitive, ranging from US$50 to US$70 per MWh for "known high-temperature resources." Overall, IEA suggests a wide range of costs, from US$50 per MWh up to US $120 per MWh for flash stations. For binary stations, the range in the USA is US$70 per MWh, up to US$120 per MWh. However, in Europe where some countries, like Germany, are drilling even deeper for

low-moderate temperature resources sufficient for power production, costs may be as high as US$200 per MWh (IEA 2010 [6]).

Cost Estimates for Installed Kilowatt (kW) As for installed cost per kilowatt, an August 2009 study by the California Energy Commission estimates costs range between US$2,700 and US$8,000 for geothermal stations (assuming a station built in 2010), with an average cost assumed of US$4,851 for binary stations and US$4,407 for flash stations, although O&M costs are assumed to be higher for flash stations (CEC 2009 [7]). Other recent studies place the range slightly narrower. US DOE, in September 2008, estimated a base cost of US$4,000 per installed kilowatt. Emerging Energy Research assumes a range of US$4,000–US $5,500/kW for projects in the 20–60 MW range (EER 2009 [3]). EER notes that larger projects, "such as those under development in Indonesia, The Philippines, and New Zealand, have shown significant advantages of increasing scale, with costs of proposed projects approaching as low as US$2,000/kW" (EER 2009 [3]), refer Fig. 1. According to the International Energy Agency, greenfield flash stations can cost as low as US $2,000 per installed kW and range up to US$4,500, particularly in high-temperature sites which may require fewer wells. They estimate binary power stations, ranging from as low as US$2,400 per installed kW for a productive high-temperature site, suitable for binary technology, to US$5,900 for low-temperature sites, particularly where many wells need to be drilled (IEA 2010 [6]). Currently, most projects in The Philippines are anticipated to be within the 20–60 MW range, as by an announcement of plans by the Energy Development Company (EDC [8]) on July 29, 2010, where upcoming projects sized 20–50 MW where referenced in its portfolio. EDC estimate costs for greenfield sites (sites that are new and not expansions to producing fields) to cost approximately US$3,500 per kilowatt installed (Source: Inquirer.net, July 29, 2010).

Comparison with Other Technologies Typically, the cost of the power station, surface facilities and transmission will constitute approximately half of the total costs of a geothermal station (Source: DOE 2008 [1] and EER 2009 [3]). This reflects the high upfront costs associated with resource assessment. For comparison, the costs to assess solar resources are relatively minor, perhaps even negligible. Yet, materials costs for solar projects are significantly higher on a levelized basis than for fossil fuels or geothermal. Generally more land is needed for economies of scale, which also adds to the costs. For example, in its August 2009 report to the California Energy Commission, KEMA [9] shows that the installed costs for Photovoltaic solar and Parabolic Trough solar technologies are roughly similar in installed cost of geothermal projects overall. However, this recognizes that most of the installed cost is materials, with little of



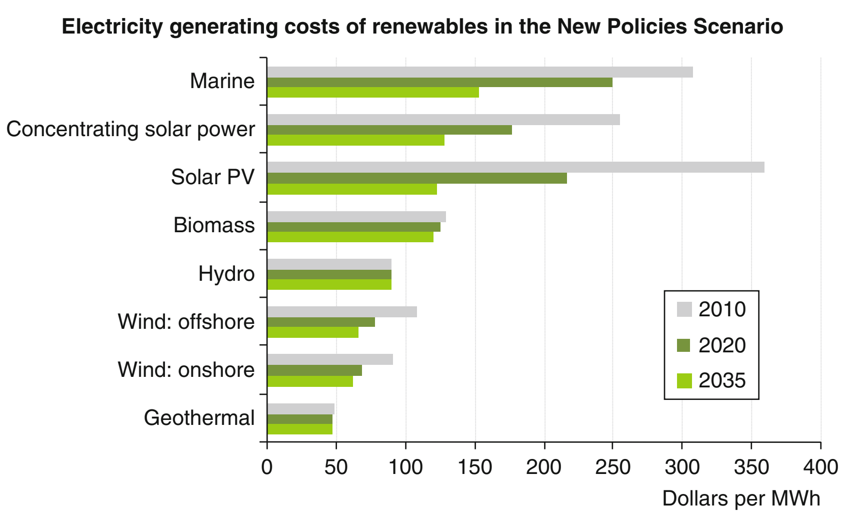
Geothermal Power Conversion Technology. Figure 1
Breakdown of capital costs for a geothermal project (Courtesy of IHS Emerging Energy Research [3], pp. 3–18)

it from actual resource confirmation. Further, capacity factors and annual average production for solar technology are generally much less than for geothermal. Whereas geothermal generally has capacity factors above 90% (CEC 2009 [7]), existing solar technologies have capacity factors between 26% and 29% (CEC 2009 [7] and CPUC 2010 [10]). According to the CEC in its "Renewable Energy Cost of Generation Update," August 2009 (pp. 206, 211, 226, 236) the capacity factor for geothermal projects averages between 90% and 94% depending on technology. On the other hand, solar thermal without storage and solar photovoltaic is between 26% and 28%. Although solar thermal with storage is expected to have much higher capacity factors (60–70%), no advanced solar projects have proposed capacity factors this high. This is reinforced by the California Public Utilities Commission (CPUC) which in its July 2010 RPS Project Status table identifies contract capacity for projects in operation and projects which have been approved by the Commission. Solar photovoltaic projects in operation and approved by the CPUC average or expect to average 25.7%, while solar thermal projects approved by the CPUC expect to average 28.8%, refer http://www.cpuc.ca.gov/NR/rdonlyres/A5406F32-B0D0-409E-AA92-0EA79E97BECC/0/RPS_Project_Status_Table_2010_ July.xls.

Further, for fossil fuels such as natural gas and coal, the risk of resource development falls to the producers of natural gas and coal, and not to the power station operators. Thus, the risk of resource development is spread widely to all natural gas and coal suppliers, creating a price range (per MMBTU for natural gas and per short-ton for coal). The price of the fuel source is thus reflected in O&M, and not the physical construction of the power station, which varies primarily according to cost of materials like metal and steel.

Should a geothermal resource be more difficult to develop or anticipate, this will be born in initial development cost, rather than the O&M, as the operator of a geothermal power station was also the developer who financed the project and incurred upfront risks. Although geothermal resources vary in sustainability and there is a range of O&M costs, much of the risk is borne in the upfront development process.

Levelized Costs For the reasons described above, levelized costs for geothermal are important considerations. The levelized cost of energy includes all the costs over the lifetime of a project. From initial investment (higher for geothermal power than fossil fuels), to construction and materials cost (similar for geothermal and fossil fuels), to operations and maintenance costs (slightly lower for geothermal than fossil fuels) and to cost of fuel (essentially zero for geothermal, whereas a major cost for fossil fuels) (Fig. 2).



Geothermal Power Conversion Technology. Figure 2
Levelized costs of renewables (IEA World Energy Outlook [6])

Geothermal Resources

For power conversion, the value of a geothermal resource is its enthalpy. All other characteristics, mineral content and noncondensable gases, are almost always a drawback to be dealt with at additional investment and cost. In case of coproduction of geothermal energy from pressurized oil or gas wells, the pressure is also of value but its sustainability is in question and requires further R&D.

Geothermal Resource Characteristics

Conventional drilling techniques are used to reach natural underground reservoirs (aquifers) containing hot water and/or steam. These geothermal fluids are under high temperature/pressure and are at bursting pressure from the well. At lower temperatures the geothermal fluid resource has to be pumped to the surface and used to produce electricity via the power conversion system or directly for space or process heating.

While the main aim is to use the heat content for power production, it is essential here to cover all the unwanted source properties (chemical and physical) and the means to mitigate their impact.

Natural geothermal systems can be divided into four categories:

- Dry steam
- Vapor-dominated
- Liquid dominated (superheated water)
- Moderate temperature water (less than 150°C)

In addition, the following are resources in experimental stages:

- Geo-pressured reservoirs
- EGS/HDR
- Lavas and magmas (not dealt with in this entry)

Although dry-steam fields are relatively rare, the Italian fields at Larderello and Mt. Amiata produce about 850 MW [12] and the US field at The Geysers in California, produce about 900 MW (net) of electricity [13, 14]. Vapor-dominated fluids are advantageous for power production as they are usually available at relatively high temperature and pressure. The steam is used to directly drive turbines [15, 16].

The more commonly occurring liquid-dominated systems present a complex utilization problem as reasonably high-pressure vapor must be created for power generation in a conventional turbo-generator unit. The fluid can be partially vaporized by flashing it to a lower pressure, in one or two flashing stages [17]. The vapor then expands in a suitable turbine to produce power [16], or in a binary station using ORC it can heat a secondary fluid vaporizing it at a lower temperature (hydrocarbon). The latter then expands in a turbine, condenses, and is pumped in a continuous closed cycle [16, 17]. A disadvantage of direct steam flashing is that multiple flashing steps are required to attain high conversion efficiencies. Only a fraction of steam is produced with a single-flashing stage. Successive flashing improves efficiency but requires complex turbine design. Furthermore, the relatively high specific volume of steam at these lower temperatures results in large, expensive turbines. Therefore, in most cases only double-flash is used.

Fluid temperatures as high as 300°C have been observed in the Imperial Valley of California, and Russian fields including Kamchatka. Liquid-dominated systems vary widely in terms of the available temperatures and pressures of geothermal fluids. For power production, temperatures above 150°C are desirable when coupled to sink (heat rejection) temperatures of approximately 25°C.

Geothermal pressured reservoirs such as those of the Gulf Coast, contain moderately hot water (150–180°C) under extremely high pressures (250–650 bars) [18]. However, utilization of this resource has been limited by engineering problems associated with drilling into such formations and extracting useful amounts of energy. Lavas and molten magmas are another potentially useful energy source, but controlled energy extraction is only in the formative research stages at this point, mainly in Iceland.

Enhanced (engineered) geothermal systems (EGS) are also under development in Europe, Japan, Australia, and the Western USA. EGS consists of drilling into hot dry rock (HDR) and creating a geothermal reservoir by hydraulically fracturing the rock [19, 20]. Water is then circulated through the fractured zone to remove heat and is pumped to the surface. Additional surface area for underground heat transfer may also be created by thermal stress cracking which will greatly enhance

the lifetime of the reservoir. Energy conversion on the surface may utilize direct steam flashing and steam turbine and/or an Organic Rankine power cycle.

Geothermal Fluid Chemistry

Geothermal fluids contain numerous minerals and dissolved gases accumulated in the underground aquifer from its creation. Utilization of the thermal energy of the extracted geothermal fluid changes the fluid's equilibrium properties when the fluid exits the wellhead. Chemical analysis enables the station operator to be prepared for changes in the fluid behavior from changes in temperature and pressure. This parameter is not only required for geothermal power station's (corrosion, scaling, etc.) functional design but also for the station environmental design. Chemical "fingerprints" might adversely affect water quality (domestic, irrigation, rivers, drainage, etc.). Steam and condensate containing "non-condensable gases" (NCG), e.g., hydrogen sulfide, traces of benzene, toxic (or even only foul-smelling) are handled according to local environmental limitations for such substances.

Reinjection of separated brines, and blow down from cooling towers are common practice in geothermal stations for environmental reasons and for reservoir replenishment.

Noncondensable Gases Two particular ingredients of geothermal fluid production are H_2S and carbon dioxide (CO_2). In most cases, CO_2 outweighs the H_2S concentration and is responsible for relatively low pH of geothermal condensates involved in calcite scaling in production wells. Calcite deposits form more readily in wells with high CO_2. Scaling is not restricted to well casings and may also impact surface piping and heat exchangers.

Hydrogen Sulfide (H_2S) In certain conditions, H_2S creates a protective iron sulfide layer on carbon steel surfaces (limiting their corrosion rate) and stabilizes "deaeration" of geothermal brines (dissolved oxygen in aerated brines dramatically increases corrosion rates). H_2S is toxic foul smelling, corrosive and scale forming with many heavy metals. A specific type of corrosion (sulfide stress cracking or SSC) can occur on high-strength ferrous materials of the steam turbine blades and/or on "high" hardness welds in geothermal fluids at high H_2S partial pressure. This is hydrogen embrittlement cracking where hydrogen is generated by the sulfide corrosion process on the metal surface.

H_2S readily forms heavy metal sulfides on cooling, or when separating steam from brine. In highly saline geothermal fluids, such sulfides may plug wellheads or heat transfer surfaces. Unique sulfide forms may result in less saline brines after cooling (antimony sulfide "stibnite"). Some heavy-metal sulfide precipitates are also suspected of causing pitting corrosion on stainless steels.

NACE standard MR0175 defines a "sour" (high H_2S containing) service, where H_2S partial pressure is above 0.05 psia (0.0003 Mpa) and requires protection of personnel and electrical equipment.

In addition, H_2S is toxic even at low air concentrations and must be mitigated to keep its levels below environmental thresholds.

Calcite Scaling in Production Well Casings One of the common problems in geothermal wells is the deposition of calcium carbonate or calcite, $CaCO_3$, in the well casing starting just above the flash horizon. It is not uncommon for high-temperature geothermal fluids to be close to saturation with respect to calcite as they flow through the formation. The solubility of calcite varies inversely with temperature, so it cannot precipitate from the geothermal fluid because of a decrease in temperature while other factors remain constant. The other properties of the geothermal fluid that influence the solubility are:

- Partial pressure of carbon dioxide CO_2
- pH
- Salinity
- Calcium ion concentration

The first two factors are interrelated. When the geothermal fluid flashes in the well, the released steam carries most of the CO_2. This causes the liquid pH to rise dramatically supersaturating the geothermal fluid (with respect to calcite). Precipitation occurs immediately and can lead to severe narrowing of the wellbore for several meters just above the flash horizon.

The chemical equilibrium reactions controlling the process are:

$$CO_2(aq) \Leftrightarrow CO_2(vap) \quad (1)$$

$$HCO_3{}^- + H^+ \Leftrightarrow CO_2 + H_2O \quad (2)$$

$$Ca^{++} + 1HCO_3 - CaCO_3 \downarrow + H_2O + CO_2 \uparrow \quad (3)$$

pH Geothermal brines and condensates can exhibit different pH values. There are also variations of measurement results related to environmental conditions at the testing point (i.e., difference between "field" and "lab" pH). At higher temperatures, "neutral" pH value lowers while on steam from water separation (flashing to lower pressure) and pH value rises due to the escape of acidic gases.

The impact of the pH value (after dealing with eventual inaccuracies) is important for design purposes:

- Influence on durability of materials in contact with the fluid. Impact on material selection for its transportation and handling (deleterious influence) on the corrosion resistance of carbon steel and lower pH.
- Influence flow rates and pressure drops by indirect effect of scaling impeding heat transfer due to fouling.
- Design may also need the pH value to adjust to lower values ("pH modification" [21]) as an antiscaling measure (to delay amorphous silica precipitation). Value can be raised to protect carbon steel from corrosion in condensate. pH values in some geothermal brines may be highly buffered by a heavy presence of bicarbonate ions. Therefore the input of pH value alone may suffice to adjust for eventual changes throughout the power station.

Dissolved Solids

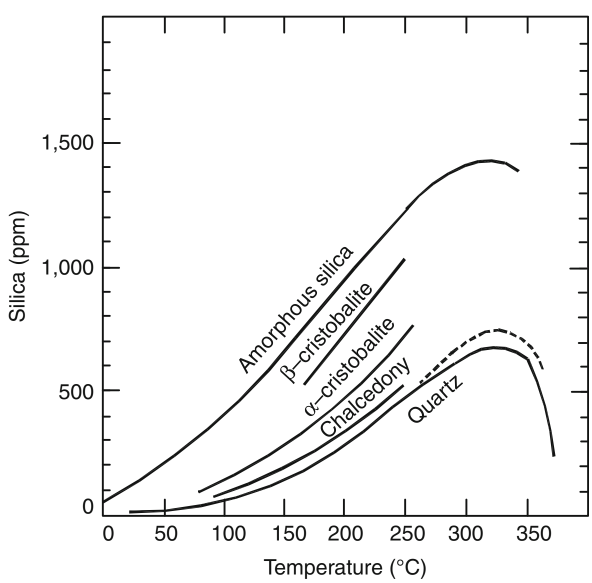
Salinity The importance of this parameter is related to geothermal brine characterization. Residual salinities may also be found in separated steam (from carryover of brine). Salinity impacts heavily on scaling problems, corrosion behavior of steel and other alloys, environmental control, etc.

Power station design includes concentrating brines by flashing the steam from them as well as cooling brines, and then mixing the brines and condensates. All this impacts the salinity and solubility of the solids constituting the brine. Some references [22] consider salinity as dissolved "solids" in water.

At geothermal power extraction pressures and temperatures, solids solubility can either increase continuously with temperature (at saturated water vapor) or decrease [22]. Such behaviors are more complex due to pH changes and gas involvement. Design and further operation have to handle solubility issues to avoid scale plugging (resulting in oversaturation of individual salts and their precipitation). Refer to following paragraph (waste brine scale potential).

Scale in Disposed Geothermal Fluid The common problem discussed in literature [21, pp. 124–128] is the "silica" issue. Here the chemistry is problematic as the resource is at higher temperatures. Silica (SiO_2) solubility in the hot reservoir is controlled by the crystalline quartz form. At lower temperatures, solubility is controlled by amorphous silica typical to waste brine. Other forms of silica may be found in geothermal precipitates as shown in Fig. 3.

The dominant scale precipitate is of amorphous silica which at intermediate temperature possesses higher solubility than the quartz (brine is



Geothermal Power Conversion Technology. Figure 3 Solubility of various forms of silica in water at saturated water vapor pressures [22, p. 146]

"supersaturated" with quartz but undersaturated with amorphous silica).

With proper process design it is possible to avoid precipitation of amorphous silica while the fluid is traveling through the station components. It is definitely possible for precipitation to occur in the injection wells or in the reservoir once the waste fluid returns to the formation. This adversely affects the formation permeability, reducing the injectability of the waste fluid. Any reheating of the waste brine in the formation reduces the potential for precipitation in the reservoir [21, p. 124]. Further aspects of silica precipitation see in [21, pp. 125, 126, 128].

The solubility of silica is not only a function of fluid temperature but also of salinity and pH. The figures shown above are for pure water. Qualitatively, for a given temperature and pH of aqueous solutions, the higher the salinity (i.e., higher molarity), the lower the solubility of both quartz and amorphous silica. For a given temperature and salinity, the solubility of amorphous silica is essentially independent of the pH for low (acidic) values, but rises dramatically as pH climbs above neutral, i.e., pH > 7. The effect is more pronounced for fluids with high salinity.

Precipitation kinetics plays a critical role in the scaling potential in geothermal station components. If precipitation can be slowed it may be possible to process the fluid and dispose of it before scaling can occur. Alternatively, if the precipitation can be accelerated, it may be possible to force the fluid to give up its scale-causing minerals in a rapid and controlled manner before it enters the station proper, allowing the purged fluid to be used without fear of further precipitation. Both of these effects have been used at stations near the Salton Sea in the Imperial Valley of the USA where highly mineralized, corrosive brines are present. There are five parameters that influence the kinetics of the silica precipitation (essentially a polymerization process):

- Initial degree of super saturation (i.e., actual SiO_2 concentration – equilibrium concentration)
- Temperature
- Salinity or molarity of the solution
- pH of the solution
- Presence (or absence) of colloidal or particulate siliceous material

The first and second factors can be controlled by proper selection of separator and flash conditions for a given geothermal fluid. The third factor is a fluid characteristic that cannot be controlled. The fourth and fifth factors can be adjusted as the fluid moves through the station from the production wells, through pipes, other components and eventually to the injection wells. When the brine is acidified, the rate of precipitation is very slow and the fluid can be viewed as temporarily stabilized. As the pH is raised, the precipitation rate increases dramatically, reaching a maximum at near-neutral pH values, about 6.0–7.5, and then slowing as pH approaches 9.0–9.5. The rates for pH = 5.3 and pH = 9.0 are roughly the same.

The last factor in the list has been utilized successfully for the Imperial Valley stations. Geothermal fluid is "seeded" with silica particles in large vessels called flash-crystallizers. These provide favorable precipitation sites for the supersaturated solution. After two stages of this process, the precipitated silica is removed, dried, compacted and disposed of. The generated steam is ready for use in turbines and the waste liquid is sufficiently clean for reinjection without fear of clogging the reservoir.

The potential for silica precipitation is mitigated to some degree when binary stations are used as the geothermal fluid is not flashed, but only cooled. Thus, there is no increase in the concentration of silica as the fluid passes through the station. Flow design in binary stations keeps the fluid in the safe region below the amorphous silica equilibrium curve. In comparison to a flash station, this allows the geothermal fluid to be cooled to a lower temperature before silica precipitation occurs.

Entrained Solids Entrained solids consist of sand and clay particles requiring temporary or permanent filters (stand or centrifugal type) to avoid corrosion damage to pipes and heat exchangers as well as clogging of the injection wells.

Material Selection in Geothermal Power Stations This issue was presented and discussed by Kestin in the Source Book on the *Production of Electricity from Geothermal Energy*-Chap. 3 [16], See Table 2.

Different applications within the power station face different requirements which are not only related to mechanical design, but also to durability problems

Geothermal Power Conversion Technology. Table 2
Typical turbine element materials [16]

Component	Material
Piping	ASTM A106, Gr B; ASTM A335, GrP11 or P22
H.P. castings	ASTM A356, k Gr I, 6, 9 or 10
L.P. castings	ASTM A285 or A515
Valve bodies	ASTM A216 or A217
Fasteners	ASTM A193 and A194
Rotors	ASTM A470
Blades	AISI 403
Nozzle blades	AISI 403
Bands	AISI 405

arising from the contact with the complex geothermal environment.

Metallic Materials Most of the construction materials used in such stations are metallic. Performance of metals and alloys in geothermal power stations has long been studied in respect to durability against availability, ease, and cost of fabrication (as in the use of steel and iron base alloys).

Furthermore, mechanical design may reach a conflict with special types of corrosion (sulfide stress cracking) that might occur during the use of some equipment made of high-strength ferrous alloys.

Different types of corrosion and environmentally assisted cracking mostly dictate the materials selection in geothermal power stations. The following corrosion and cracking forms can appear:

- Generalized (or "uniform") corrosion
- Localized corrosion (pitting, "crevice")
- Stress corrosion cracking (mostly induced by chloride ions)
- Sulfide stress cracking
- Fatigue corrosion (synergistic effect of cyclic stress and corrosion)
- Erosion-corrosion (accelerated corrosion by impingement of particles, gas bubbles, droplets, or too high fluid velocity)

Poor operating conditions might impact durability, even after applying a good design and materials selection. Among these conditions:

- "Shutdown corrosion," mostly generating or accelerating uniform and localized attack due to air (oxygen) ingress, water stagnation, corrosion products transformation. This corrosion is caused by frequent or long-term shutdowns without proper preservation actions.
- Bad monitoring or no application of designed corrosion inhibitors added to geothermal fluid.
- Bad or no monitoring of the designed steam quality.
- Unsuitable locally made repairs (like welding).
- Introduction of new geothermal fluid resources.
- Change of flow and temperature conditions.

Geothermal steam turbines are normally fed directly from the production wells, after separation from brine or as slightly superheated steam. Corrosive gases and entrained salts (from brine carryover) impose serious design problems on the turbine, steam transportation system and other ancillary parts. The situation may be more complex due to variations in steam composition (even at the same station).

Geothermal steam turbine manufacturers have established standards for materials selection based on manufacturer experience and material testing:

- For turbine rotors (forgings), some [24] used "low chrome-moly" steel (CrMo steel) and others [16] used "chrome-moly-vanadium" steel or "nickel-chrome-moly-vanadium" steel.
- For moving blades 13 chromium stainless steel.
- For the casings, grey cast iron or carbon steel.
- For steam pipes (large diameter) and silencers, rolled steel.

Sometimes cladding or coating is applied on critical parts:

- Epoxy coating on carbon steel exhaust duct and discharge pipes.
- "Stellite" hard facing on governing valve disc made of cast steel or on check valve made of forged steel [25].
- Austenitic stainless steel type 316L (S.S. 316L) was used as cladding on carbon steel used for condenser shell and for steam separator casing.

Steam turbine equipment also consists of other related parts in contact with steam, separated wet gases and wet air which comprise (partial list):

- Ejectors exhaust and tail pipes (S.S. 316L), condenser spray nozzles (S.S. 316L)

In binary geothermal power stations that are using organic fluids (propane, butane or pentane) there is no corrosion on the motive fluid side. This enables the choice of materials based on mechanical strength only, (i.e., low alloy carbon steel, aluminum or titanium for high speed centripetal expanders) such as low alloy carbon steel, aluminum or titanium for high speed centripetal expanders. The main corrosion issue is encountered in the piping and tubing parts in contact with the geothermal fluid. In most such applications, the use of mild steel benefits from the total deaeration of the geothermal brines which naturally occurs at normal pressurized fluid conditions. Separated brines also benefit from the loss of corrosive CO_2 and H_2S, (of which a high proportion escapes with the separated steam), and of the resulting higher pH. Both factors (oxygen and pH) may contribute to lower corrosion rates and to reasonable durability of such low-cost material. In some cases, high salinities or high sand content may generate localized corrosion, erosion-corrosion or under-deposit corrosion, requiring different materials such as stainless steel (including duplex) or titanium.

Due to the high presence of corrosive CO_2 in such a fluid, special precautions must be applied on transporting downhole pumped brines inside mild steel piping.

When thin wall tubing (heat exchangers used to evaporate or preheat the working fluid) is applied, stainless steel or even Titanium is selected. Recently, "duplex" stainless steel tubes have been successfully used [23].

Atmospheric Corrosion Geothermal power stations' atmospheric environment might also have an abnormal presence of H_2S and NH_3 gases. These gases together with humidity can attack copper and other metallic materials. This is in addition to carbon steel rusting due to CO_2 presence with steam escaping into the atmosphere.

Galvanized steel, stainless steel, aluminum, and epoxy coatings are preferably used against atmospheric corrosion. Electronic equipment requires special attention, i.e., pressurized shelters, corrosion resistant contacts, and appropriate insulation.

Nonmetallic Materials While nonmetallic materials are not useful in heat transfer equipment (used only for sealing purposes), such materials find use in the transportation of cooled brines or cooling water pipes (made of fiber reinforced plastics (FRP) or polyethylene).

Internally cement-coated steel pipes are used to transport hyper saline geothermal brines. Cements also find large applications in geothermal well completion and civil works.

Thermodynamic Analysis of the Energy Conversion Process

Introduction

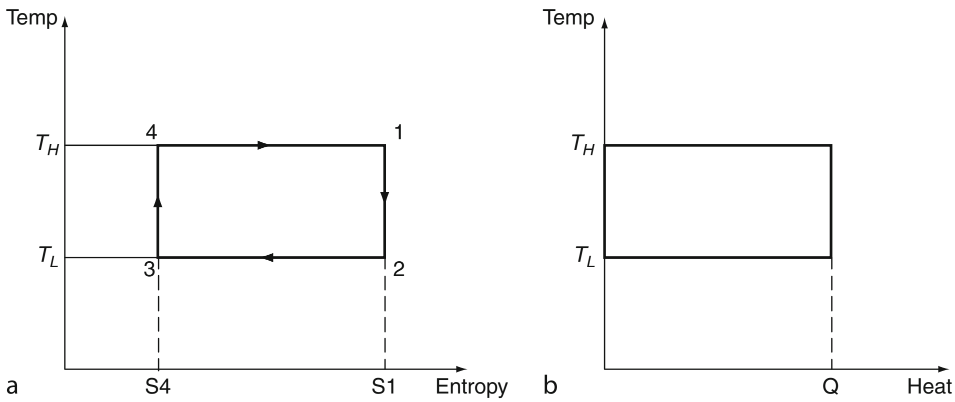
For a comprehensive thermodynamic analysis including Energy analysis applied to geothermal power systems from fluid supply to energy conversion including ancillary equipment (separators, cooling towers, etc.) [33].

Available Energy

Energy Conversion Process in Geothermal Power Stations It is assumed that geothermal fluids are utilized in continuous steady state in the energy conversion process. This assumption allows thermodynamic analyses of such systems whether water or steam dominated. The First and Second Law of thermodynamics are used to calculate the maximum available energy and the expected cycle efficiency.

First and Second Law of Thermodynamics The First Law of thermodynamics is the application of the conservation of energy principle to heat and thermodynamic processes.

Maximum Mechanical Energy Available Kestin [26] converting heat into mechanical energy is governed by the Second Law. The maximum mechanical energy which can be obtained from



Geothermal Power Conversion Technology. Figure 4
T-S (**a**) and T-Q (**b**) diagrams showing the available mechanical energy

the geothermal fluid provided by a constant temperature (T_H) reservoir is achieved by using an ideal heat engine (the Carnot engine). This produces work and discards heat into a low constant temperature (T_L) reservoir.

The maximum conversion efficiency is expressed by:

$$\eta_C = \frac{T_H - T_L}{T_H} \tag{4}$$

T-Q diagrams are used to allow direct energy analysis of the heat source and heat utilization. A T-Q diagram of the general Carnot cycle of Fig. 4a is given in Fig. 4b. The above is applied to the four different categories of fluids obtained from geothermal sources where T_H and T_L are the absolute temperatures of the heat source and heat sink.

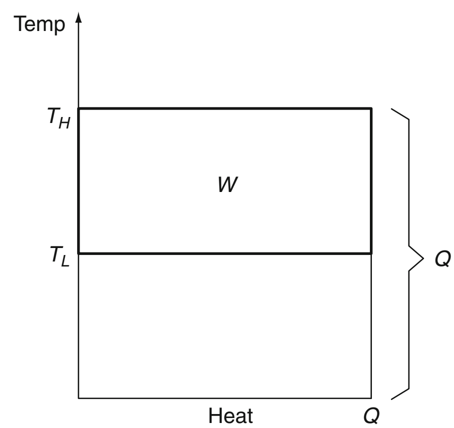
Dry Steam The supply of steam can be considered a constant temperature heat source where the ambient can be considered a constant temperature heat sink.

The relevant T-Q diagram is given in Fig. 5 which is similar to that of Fig. 4b.

$$\eta_C = \frac{T_H - T_L}{T_H} \tag{5}$$

Where Q is the heat source and W, the corresponding work obtained:

$$W = \frac{T_H - T_L}{T_H} Q \tag{6}$$



Geothermal Power Conversion Technology. Figure 5
T-Q diagram of dry-steam utilization

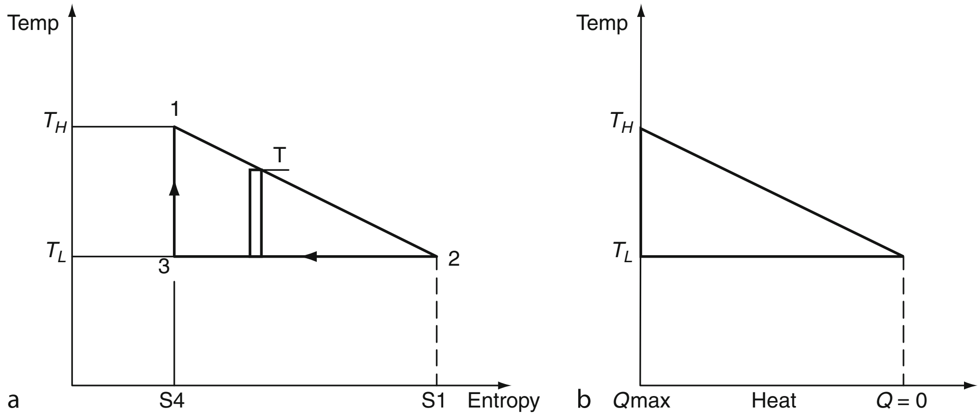
Pressurized Water In this case, the temperature of the heat being transferred to the cycle by the geothermal water drops during the heat transfer operation and therefore Eq. 5 does not apply here. To calculate maximum efficiency the cycle is represented by a series of infinitesimally narrow Carnot cycles between temperatures T_H and T_L, see Fig. 6a.

Therefore for each engine i:

$$\mathrm{d}W_i = \frac{T_i - T_L}{T_i} \mathrm{d}Q \tag{7}$$

and for the cycle:

$$W = \int_O^Q \frac{T - T_L}{T} \mathrm{d}Q = \left[1 - \frac{\ln \frac{T_H}{T_L}}{\frac{T_H}{T_L} - 1} \right] Q \tag{8}$$



Geothermal Power Conversion Technology. Figure 6
T-S (**a**) and T-Q (**b**) diagrams for pressurized or low-temperature water cycle

The efficiency is:

$$\eta = 1 - \frac{1n\frac{T_H}{T_L}}{\frac{T_H}{T_L} - 1} \tag{9}$$

Steam Dominated:

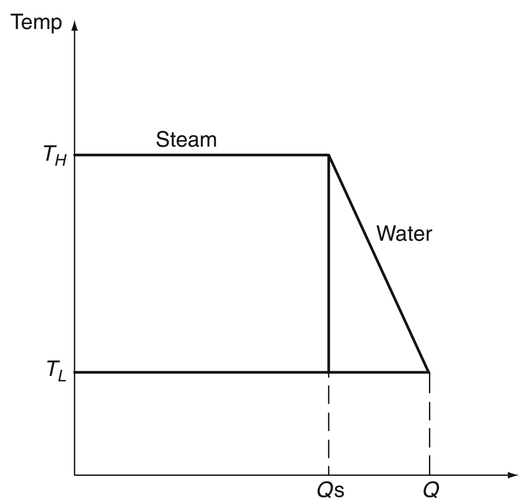
1. “Dry Steam” (majority of energy in the steam)
2. “Pressurized Water” (majority of energy in the water or sensible heat part) (Fig. 7).

If Q is the total heat constant of the fluid and r is the ratio of the latent heat portion of the total heat. Then the maximum efficiency of mechanical energy available from this source is:

$$W = \left\{ \left(\frac{T_H - T_L}{T_H} \right) r + (1 - r) \left[\frac{1 - \ln\frac{T_H}{T_L}}{\frac{T_H}{T_L} - 1} \right] \right\} Q \tag{10}$$

Liquid Dominated Liquid-dominated case is as in the section on “Steam Dominated” with most of the energy in the water or brine portion. The formula here is the same but the maximum available mechanical energy (or efficiency) from the same total heat is smaller due to smaller r (Fig. 8). In both cases above the combined efficiency depends on r and is expressed by:

$$Ws = w\left\{ \left(\frac{T_H - T_L}{T_H} \right) r + (1 - r) \left[\frac{1 - \ln\frac{T_H}{T_L}}{\frac{T_H}{T_L} - 1} \right] \right\} Q \tag{11}$$



Geothermal Power Conversion Technology. Figure 7
T-Q diagram for steam-dominated cycle

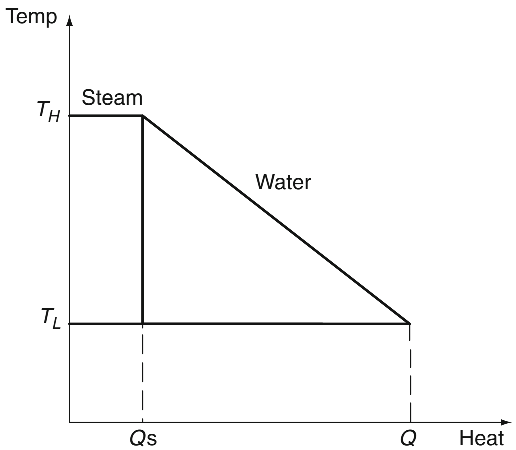
Maximum Specific Power Using Eq. 11, the maximum specific energy (kW) contained in a unit mass flow (kg/s) of a given heat source, which corresponds to maximum specific power (kW s/kg) is:

$$Ws_{\max} = \dot{W}_{\max}/\dot{m} = h_1 - h_0 - T_0(s_1 - s_0) \tag{12}$$

In Eq. 12, state 1 corresponds to the fluid high-temperature condition and state 0 corresponds to the ambient or heat sink condition.

For a given fluid, a fixed T_0 and reinjection temperature of the geothermal fluid T_{gf}^{out}, having a minimum

value of T_0, the maximum work (per unit weight of geothermal fluid) possible from an ideal, reversible process is a function of T_{gf}^{int} only, the geothermal source temperature. Calculations of the relevant curves are given Fig. 9 for both saturated geothermal steam and water. Any real process will have inefficiencies or nonreversible steps that will result in net work less than *Ws*.



Geothermal Power Conversion Technology. Figure 8
T-QS diagram for liquid-dominated cycle

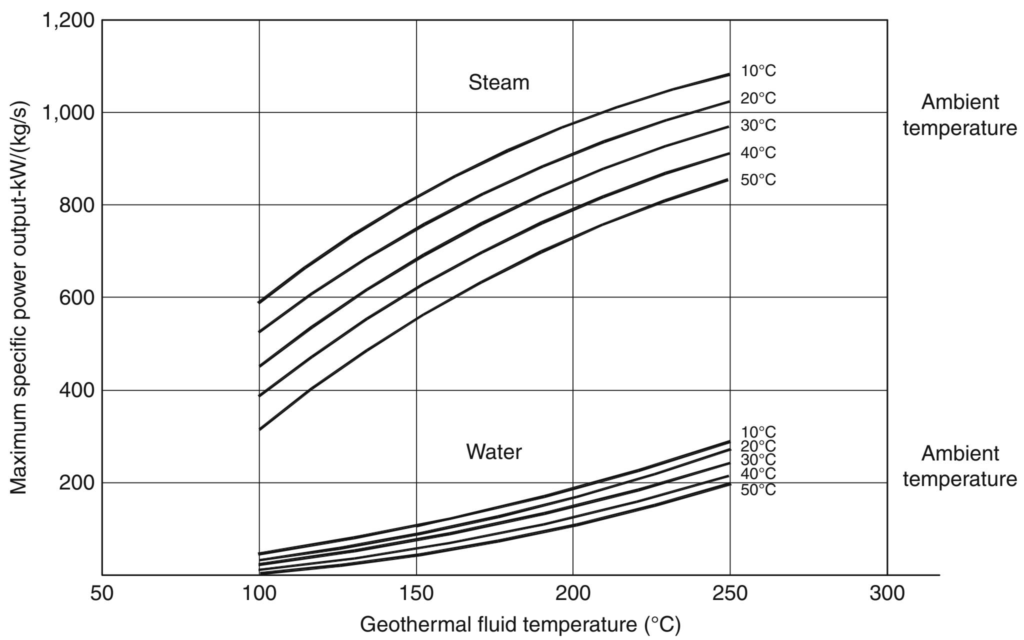
The curves in Fig. 9 allow quick assessment of the maximum power output that can be achieved from a geothermal well producing either water or steam or both. The required parameters are the fluid mass flow rate (in kg/s), fluid mass equilibrium initial temperature, and the ambient temperature or cooling water temperature.

The Temperature Limitation

- The maximum temperature at the inlet to the turbine is T_H, which is the temperature at the well head.
  In practice, the inlet temperature to the turbine is lower because of either the flashing process or the heat transfer in the evaporator.
- The lowest possible temperature T_L of the heat sink (the temperature of condensation at the turbine exhaust) is the ambient temperature T_0.
  - In practice this temperature is higher because of the irreversibility condensers, evaporator, preheaters, and cooling towers.

Power Conversion Processes Cycles

Steam Rankine Cycle Dry-steam power stations were the first type of geothermal power stations to achieve commercial status. The first small steam engine



Geothermal Power Conversion Technology. Figure 9
Maximum specific power output as function of geothermal fluid (steam and water) temperature and ambient temperature

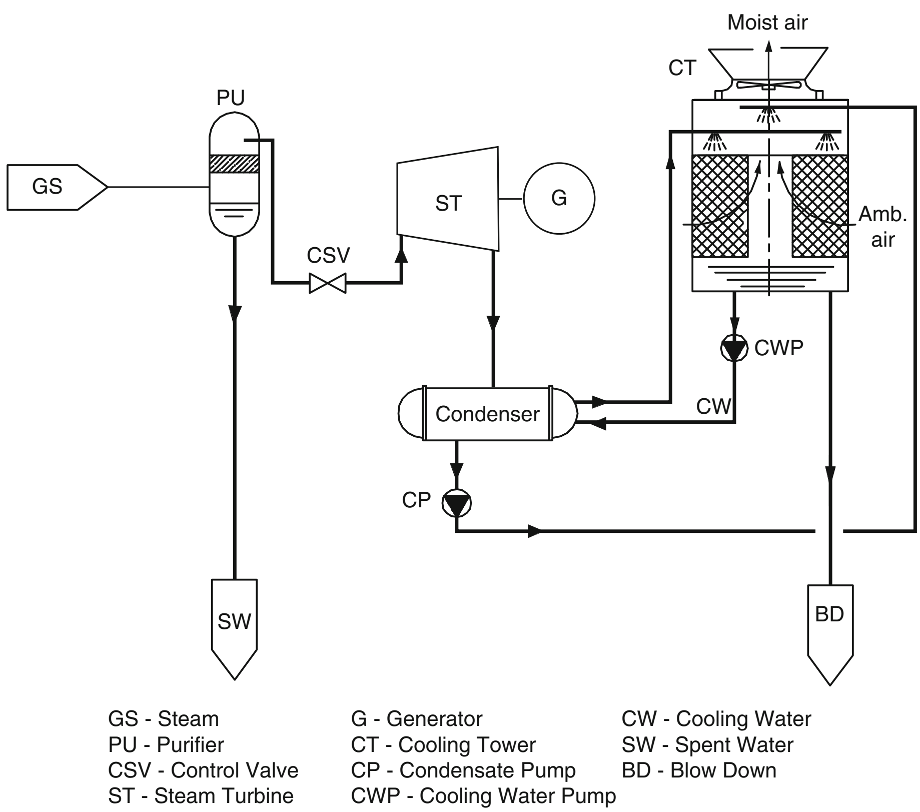
was operated in 1904 at Larderello in the Tuscany region of Italy [12].

Dry-steam power stations are simpler and less expensive than flash-steam or binary power stations as there is no geothermal brine to deal with.

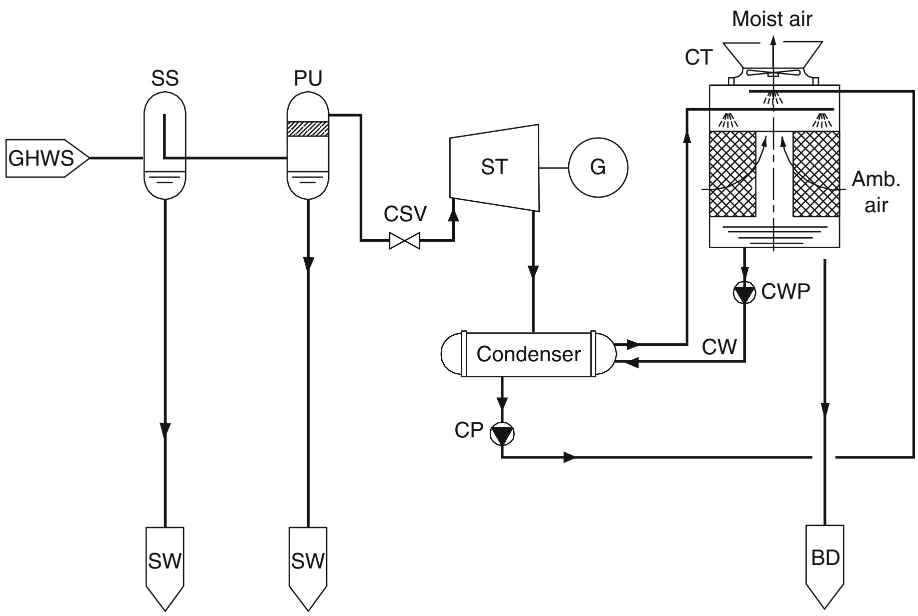
Large dry-steam reservoirs have been discovered only in two areas of the world, Larderello and The Geysers. There are limited dry-steam areas in Japan (Matsukawa), Indonesia (Kamojang), New Zealand (Poihipi Road section of Wairakei) and the USA (Cove Fort, Utah). White [27] estimated that only about 5% of all hydrothermal systems with temperatures greater than 200°C are of the dry-steam type.

The general characteristic of a dry-steam reservoir is that it comprises of porous rocks featuring fissures or fractures, either occluded or interconnected, that are filled with steam. Whereas the steam also contains gases such as carbon dioxide, hydrogen sulfide, methane and others in trace amounts, there is little or no liquid present.

The dry steam extracted from the mentioned resources is either saturated or slightly superheated at temperatures near 235°C and at a pressure near the maximum saturation in Mollier curve (30.7 bar). Isenthalpic pressure loss in the upper layers explains the superheated condition at the turbine inlet. Steam from dry-steam reservoirs is superheated due to the pressure drop during the flow through the hot rock at constant temperatures. James [28] estimated the superheating of up to 35°C (above the saturation point). Typical dry-steam power conversion system is given in Fig. 10. The steam only needs final purifying before being sent to the turbine with the condensate used as makeup for the cooling tower. The wastewater collected at the bottom of the purifier and the blow-down of the cooling tower are injected to the aquifer. This eliminates environmental problems and helps in renewal of the aquifer liquids balance.



Geothermal Power Conversion Technology. Figure 10
Power conversion system for dry steam



Geothermal Power Conversion Technology. Figure 11
Power conversion system for single-flash steam supply

The power conversion section of a single-flash system is similar to that of dry steam except for the steam preparation that requires adequate separation between the steam and water ahead of the steam purifier as given Fig. 11.

Expansion Process Thermodynamic state diagrams are used for easy understanding of the fluid working cycle. A temperature–entropy (T-S) diagram for the single-flash station is shown in Fig. 12. The Mollier h-s diagram that is alongside it may be preferred as the vertical axis shows the exact turbine work $h_4 - h_5$, and it is easily used for efficiency evaluation. The turbine efficiency in the wet zone is lower than in the dry zone mainly due to appearance of small droplets in the expanding steam. To find the turbine efficiency, use a Mollier diagram as in Fig. 12 where $\Delta h_{\mathrm{is}} = h_4 - h_{5S}$. Make a first assumption of 0.8 which finds X_{51}, (steam dryness at state point 51. The dryness fraction is x = Mass of dry steam/Total mass of wet steam). According to this the turbine efficiency can be found by use of the information on turbine efficiency in the dry and wet zones according to Bauman in [29] or Thermoflow practical assumptions [30].

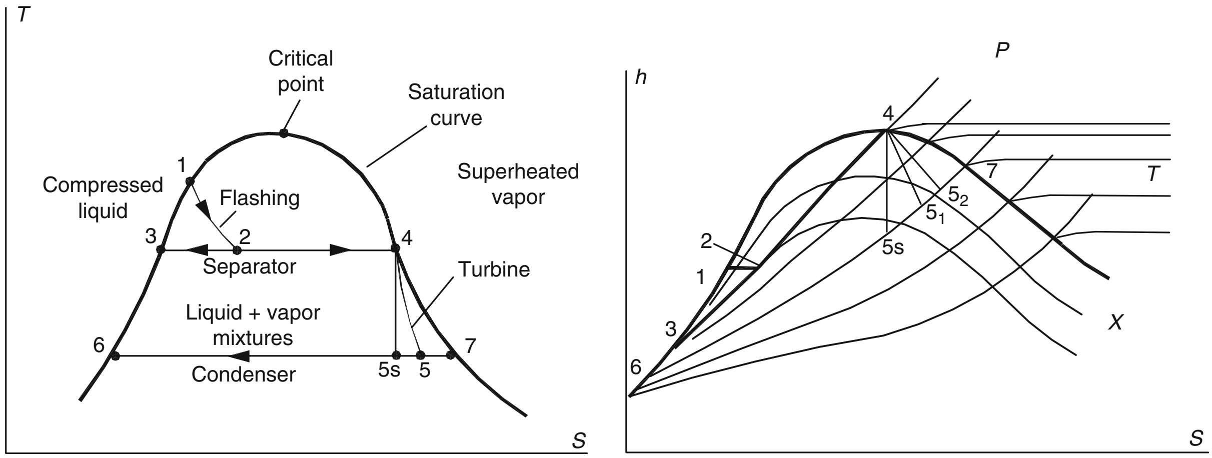
$$\Delta h_{\mathrm{first}} = h_4 - h_{51} = 0.8^{*}\Delta h_{\mathrm{is}} \rightarrow X_{51} \rightarrow \eta_{\mathrm{isw}} = \eta_t \tag{13}$$

From η_t obtain the final enthalpy drop:

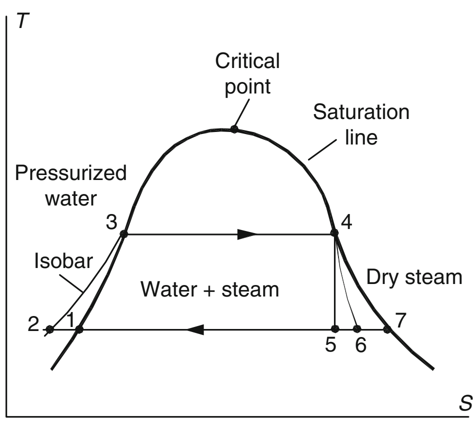
$$\Delta h_{\mathrm{final}} = h_4 - h_{52} = \Delta h_{\mathrm{iS}}{}^{*}\eta_t \tag{14}$$

The steam process of a fuel-driven dry-steam station with and without superheating is shown in Fig. 12. Water is pumped to the boiler (1–2), heated (2–3–4), steam is produced that expands from point 4 to 6 in the non-superheated or from 4 to 6 in the superheated case. At the lower pressure the steam is condensed and pumped back to the boiler to complete the cycle (Fig. 13).

In the geothermal dry-steam case the cycle is partial. Since the wells produce saturated steam (or slightly superheated steam), the starting point is located on the saturated vapor curve. The turbine



Geothermal Power Conversion Technology. Figure 12
T-S and H-S state diagrams for single-flash stations



Geothermal Power Conversion Technology. Figure 13
Temperature-entropy diagram for dry-steam power station (steam saturated at the turbine inlet)

expansion process 1–2 generates less power output than the ideal, isentropic process 1–2s. Heat is rejected to the surroundings in the condenser via the cooling water in process 2–3.

The actual work produced by the turbine per unit mass of steam flowing through it is given by:

$$w_1 = h_1 - h_2 \tag{15}$$

The maximum possible work would be generated if the turbine operated adiabatically and reversibly, i.e., at constant entropy or isentropically. Therefore, the isentropic turbine efficiency η_t, is the ratio of the actual work to the isentropic work, namely:

$$\eta_t = \frac{h_1 - h_2}{h_1 - h_{2s}} \tag{16}$$

The power developed by the turbine is given by:

$$\dot{W}_1 = \dot{m}_s w_1 = \dot{m}_s(h_1 - h_2) = \dot{m}_s \eta_t (h_1 - h_{2s}) \tag{17}$$

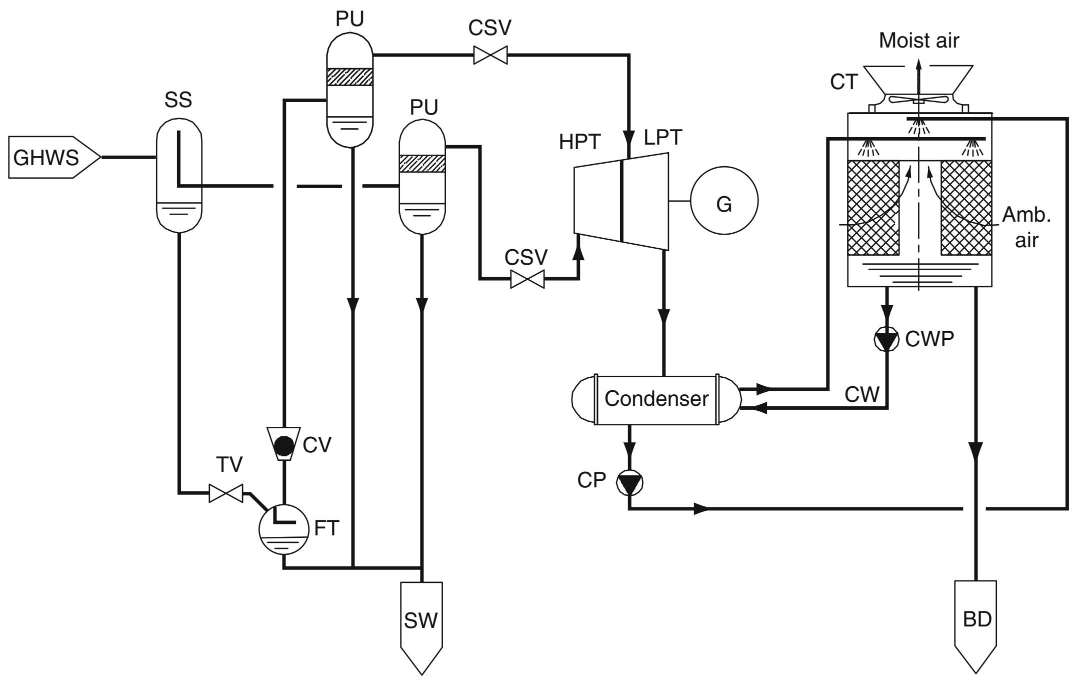
The gross electrical power will be equal to the turbine power multiplied by the generator efficiency:

$$\dot{W}_e = \eta_g \dot{W}_1 \tag{18}$$

The net power is further reduced by all parasitic loads including condensate pumping power, cooling tower fan power, etc.

High-Pressure and Low-Pressure Turbine Expansion Processes The processes for the double-flash turbine are shown in Figs. 14 and 15 below. The second flash is of the brine separated by the first steam separator.

Using the assumptions of no heat losses, no change in potential and kinetic energy as in a single-flash system, (refer to "Expansion Process"), the power



GHWS - Steam and Water
SS - Steam Separator
PU - Purifier
CSV - Control Steam Valve
HPT - High Pressure Turbine
LPT - Low Pressure Turbine
G - Generator
CT - Cooling Tower
CP- Condensate Pump
TV - Throttling Valve
CWP - Cooling Water Pump
CW - Cooling Water
SW - Spent Water
BD - Blow Down
CV - Check Valve
FT - Flash Tank

Geothermal Power Conversion Technology. Figure 14
Double-flash system with dual-pressure turbine

generated by each separated stage of the turbine can be evaluated.

The expansion work of the HP-stage is expressed by:

$$w_{hpt} = h_4 - h_5 \tag{19}$$

As in the case of the single flash the efficiency is:

$$\eta_{hpt} = \frac{h_4 - h_5}{h_4 - h_{5s}} \tag{20}$$

Accordingly, the total work depends on the mass flow:

$$\dot{W}_{hpt} = \dot{m}_{hps} w_{hpt} = x_2 \dot{m}_{total} w_{hpt} \tag{21}$$

X_2 is dryness at state 2 (see Fig. 15). The actual outlet state from the high-pressure section of the turbine is found using the Baumann rule [29] and by use of a Mollier $h - s$ steam chart [31, 32].

$$h_5 = \frac{h_4 - A\left[1 - \frac{h_6}{h_7 - h_6}\right]}{1 + \frac{A}{h_7 - h_6}} \tag{22}$$

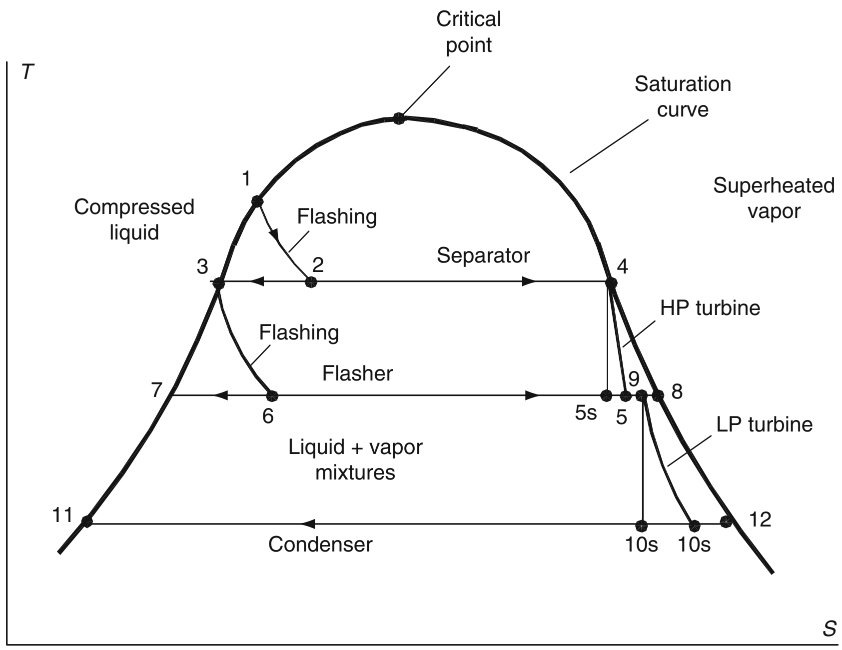
where the factor A is defined as:

$$A = 0.425(h_4 - h_5) \tag{23}$$

The low-pressure steam from the flasher is actually saturated vapor (state 8) which is admitted to the steam path and joins the partially expanded high-pressure steam at state 5. The mixed steam, ready to enter the low-pressure turbine stages is at state 9. The First Law of thermodynamics and conservation of mass allow finding the properties of the mixed state 9:

$$\dot{m}_5 h_5 + \dot{m}_8 h_8 = (\dot{m}_5 + \dot{m}_8) h_9 \tag{24}$$

$$h_9 = \frac{x_2 h_5 + (1 - x_2) x_6 h_8}{x_2 + (1 - x_2) x_6} \tag{25}$$



Geothermal Power Conversion Technology. Figure 15
Temperature-entropy process diagram for double-flash station with a dual admission turbine

The low-pressure turbine may now be analyzed as follows:

$$w_{lpt} = h_9 - h_{10} \tag{26}$$

$$\dot{W}_{lpt} = \dot{m}_9(h_9 - h_{10}) = (\dot{m}_5 + \dot{m}_8)(h_9 - h_{10}) \tag{27}$$

Again, using the Baumann rule [29] and steam Molier chart [31, 32]:

$$h_{10} = \frac{h_9 - A\left[x_9 - \frac{h_{11}}{h_{12}-h_{11}}\right]}{1 + \frac{A}{h_{12}-h_{11}}} \tag{28}$$

$$A = 0.425(h_9 - h_{10s}) \tag{29}$$

$$h_{10s} = h_{11} + [h_{12} - h_{11}]x\left[\frac{s_9 - s_{11}}{s_{12} - s_{11}}\right] \tag{30}$$

$$\eta_{\text{lpt}} = \frac{h_9 - h_{10}}{h_9 - h_{10s}} \tag{31}$$

The total power generated is the sum of the power from each turbine:

$$\dot{W}_{\text{total}} = \dot{W}_{\text{hpt}} + \dot{W}_{\text{lpt}} \tag{32}$$

Finally, the gross electrical power is found from:

$$\dot{W}_{e,\text{gross}} = \eta_g \dot{W}_{\text{total}} \tag{33}$$

Condensing Process In the use of surface-type condenser shown in Fig. 16a, the required flow rate of cooling water $\dot{m}_{\text{cw}}$ related to the steam flow rate $X_2\dot{m}_{\text{st}}$ is expressed by the First Law of thermodynamics as:

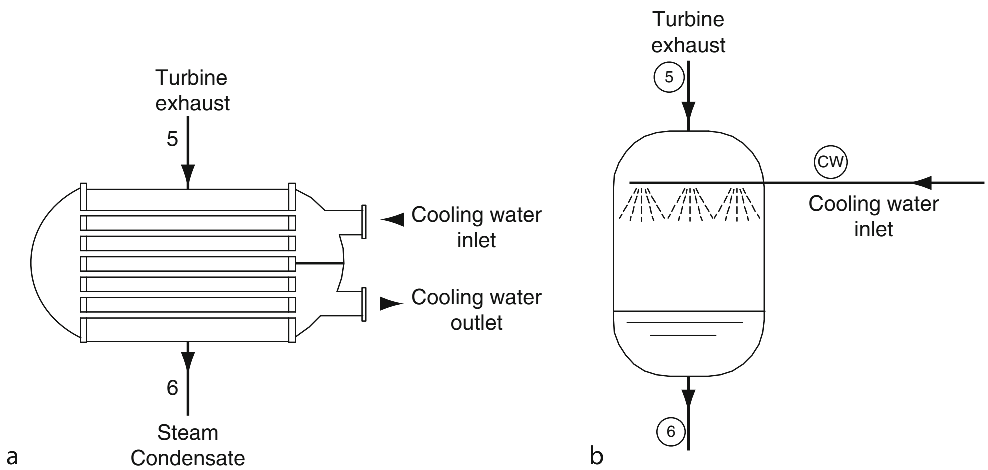
$$\dot{m}_{\text{cw}} = X_2\dot{m}_{\text{st}}\left[\frac{h_5 - h_6}{\bar{c}\Delta T}\right] \tag{34}$$

where $\bar{c}$ is the assumed constant specific heat of the cooling water (4.2 kJ/kg.K), ΔT is the rise in cooling water temperature at the condenser inlet and outlet and X_5 is the steam dryness stage at the turbine exit.

For a direct-contact condenser (Fig. 16), the equation is:

$$\dot{m}_{\text{cw}} = x_2\dot{m}_{\text{total}}\left[\frac{h_5 - h_6}{\bar{c}(T_6 - T_{\text{cw}})}\right] \tag{35}$$

Overall Thermal Efficiency The performance of the entire station may be assessed using the Second Law of thermodynamics. This by comparing the actual



Geothermal Power Conversion Technology. Figure 16
Surface (**a**) and direct contact (**b**) condensers

power output to the maximum theoretical power that could be produced from the given geothermal fluid. This involves determining the rate of energy carried into the station with the incoming geothermal fluid.

The specific maximum energy of a fluid that has a pressure, P, temperature T in the presence of an ambient pressure P_0 and an ambient temperature T_0, is given by:

$$\dot{W}_{\max} = h(T,P) - h(T_0,P_0) - T_0[s(T,P) - s(T_0,P_0)] \tag{36}$$

To get the maximum theoretical thermodynamic power, this term is multiplied by the total incoming geothermal fluid mass flow rate:

$$\dot{E} = \dot{m}_{\text{total}} \cdot \dot{W}_{\max} \tag{37}$$

The ratio of the actual net power to the maximum power is defined [33] as the utilization efficiency or the Second Law efficiency of the station:

$$\eta_u \equiv \frac{\dot{W}_{\text{net}}}{\dot{E}} \tag{38}$$

Stations can be designed to maximize η_u when the value of the primary energy is a significant factor in the economics of the operation.

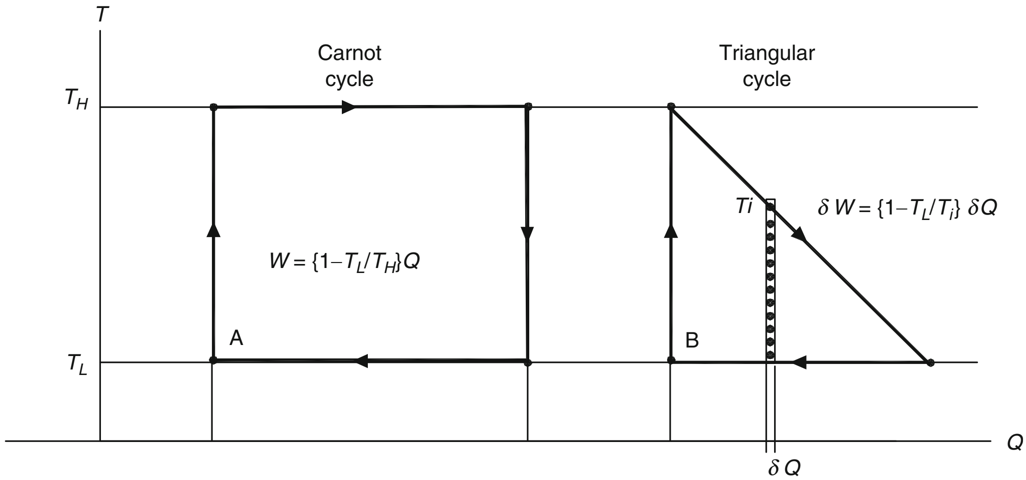
Organic Rankine Cycle Configurations For low-temperature resources, the efficiency of the flash steam cycle led many researchers to propose cycles which enhance the thermal efficiency and utilization of the geofluid energy content. Some of the ideas were executed into working power stations but did not mature into a commercial stage. The systems that are commercial begin with the simple Organic Rankine cycle (using pentane), or super critical cycles (using butane or flouro-carbons), geothermal combined cycle, and other additional similar concepts that will be discussed hereafter. The noncommercial, experimental ideas is included in section on "Experimental Power Stations."

Ideal Organic Rankine Cycle As already mentioned in "Pressurized Water," the hot water or brine is not an isothermal heat source as it cools while transferring heat to the working fluid. A more realistic ideal cycle for a geothermal binary station is a triangular cycle consisting of an isobaric (constant pressure) heat addition process up to the brine inlet temperature T_H, followed by an isentropic expansion and an isothermal heat rejection process at T_L to complete the cycle. See Fig. 17.

The efficiency for such a cycle was expressed in Eq. 9 as:

$$\eta_{TC} = 1 - \frac{T_L}{T_H - T_L} \ln\left(\frac{T_H}{T_L}\right) \tag{39}$$

For the same temperature range of 150°C and 40°C, the triangle cycle yields an efficiency of 14.3% compared with 26% for the constant temperature case.



Geothermal Power Conversion Technology. Figure 17
Two ideal thermodynamic cycles: constant temperature and continuous reducing temperature

Organic Rankine Cycle Based Power Generation Process Unlike dry-steam and flash-steam power stations, binary stations do not have condensate to serve as makeup for a water cooling tower. As a result, binary stations need a separate cooling medium, either fresh water or air.

In its simplest form, the binary station follows the schematic flow diagram in Fig. 18 for a water-cooled system [35] and in Fig. 19 for an air-cooled system [36].

The working fluids thermodynamic process are shown in Fig. 20. Due to the inclination of the saturation curve, the vapor expansion extends further into the superheated zone.

The main cycle components will be analyzed later using the state points on Fig. 20.

The supply of heat to the Organic Rankine cycle completes the conversion process and is shown in the two cases. The supply of hot water/brine or supply of steam as shown in Fig. 21. In (a) the sensible heat supply is only by hot water or brine, while in (b) the sensible heat and latent heat are from steam.

Hot geofluid is supplied to the evaporator and from there it flows to the preheater and is then returned to the injection well. The working fluid flows through a preheater where it is brought close to its boiling point. It then flows to the evaporator E where it acquires the supplement heat of evaporation. Emerging as a saturated vapor it expands in the turbine, condenses in the condenser and is pumped back to the preheater via a feed pump.

Turbine Analysis The vapor expands in the turbine between points 1 and 2 of Fig. 20.

Assuming the usual of steady adiabatic operation, the power is determined from:

$$\dot{W}_t = \dot{m}_{\mathrm{wf}}(h_1 - h_2) = \dot{m}_{\mathrm{wf}}\eta_t(h_1 - h_{2s}) \tag{40}$$

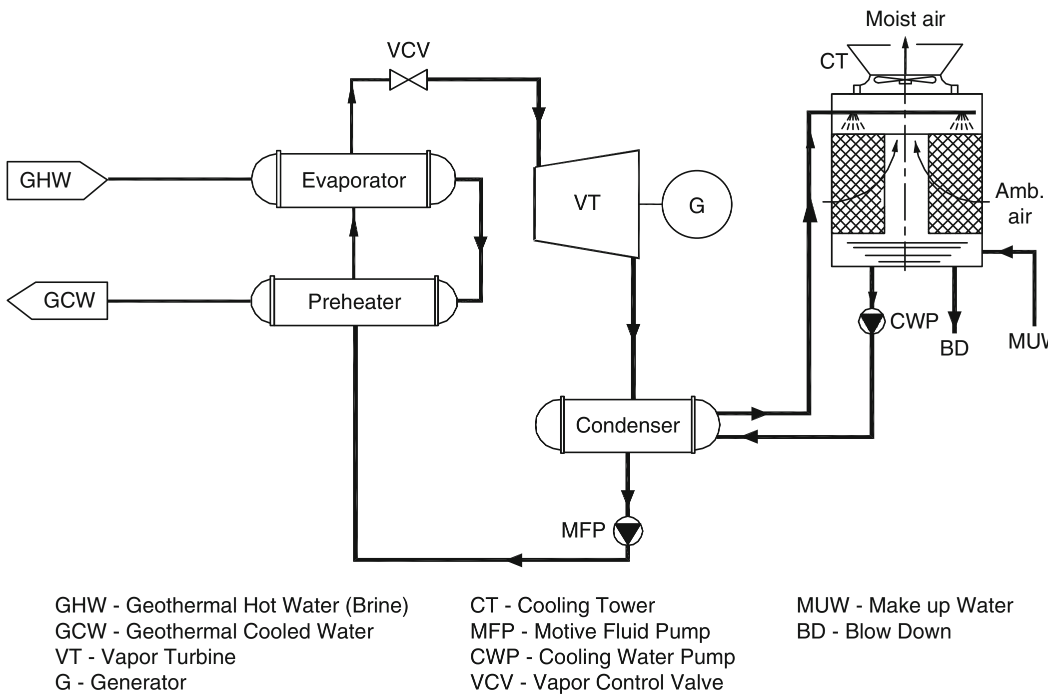
where η_t is the isentropic turbine efficiency (known parameter – the organic working fluid $\dot{m}_{\mathrm{wf}}$ expands into the superheated zone). For a given working fluid, the thermodynamic properties can be found from fluid tables for selected design parameters. Selection of the turbine power output then helps determining the required working fluid mass flow rate.

Feed Pump Analysis Using similar assumptions as for the other components, the power imparted to the working fluid from the feed pump (points 3–4 of Fig. 20) is:

$$\dot{W}_p = m_{\mathrm{wf}}(h_4 - h_3) = \dot{m}_{\mathrm{wf}}(h_{4s} - h_3)\eta_p \tag{41}$$

where η_p is the isentropic pump efficiency.

Condenser Analysis Condenser heat rejection occurs between points 2 and 3 on the cycle diagram in of Fig. 20).



Geothermal Power Conversion Technology. Figure 18
Simplified schematic of a water-cooled binary geothermal power station [35]

The heat that must be rejected from the working fluid to the cooling medium, either water (shown here) or air, is given by:

$$Q_c = \dot{m}_{\mathrm{wf}}(h_2 - h_3) \tag{42}$$

The relationship between the flow rates of the working fluid and the cooling water is:

$$\dot{m}_{\mathrm{cw}}(h_{\mathrm{out}} - h_{\mathrm{in}}) = \dot{m}_{\mathrm{wf}}(h_2 - h_3) \tag{43}$$

Assuming a constant specific heat $\bar{c}$ for cooling water temperature between T_{out} and T_{in}, the cooling water mass flow rate can be found from:

$$\dot{m}_{\mathrm{cw}}\bar{c}(T_{\mathrm{out}} - T_{\mathrm{in}}) = m_{\mathrm{wf}}(h_2 - h_3) \tag{44}$$

or

$$\dot{m}_{\mathrm{cw}} = m_{\mathrm{wf}} \frac{(h_2 - h_3)}{\bar{c}(T_{\mathrm{out}} - T_{\mathrm{in}})} \tag{45}$$

Equation 44 will change to:

$$\dot{m}_{\mathrm{cair}}(h_{\mathrm{airout}} - h_{\mathrm{airin}}) = \dot{m}_{\mathrm{wf}}(h_2 - h_3) \tag{46}$$

Assuming constant specific heat Cp for air in the relevant temperature range and neglecting humidity influence then:

$$\dot{m}_{\mathrm{cair}} Cp_{\mathrm{air}}(T_{\mathrm{airout}} - T_{\mathrm{airin}}) = \dot{m}_{\mathrm{wf}}(h_2 - h_3) \tag{47}$$

or

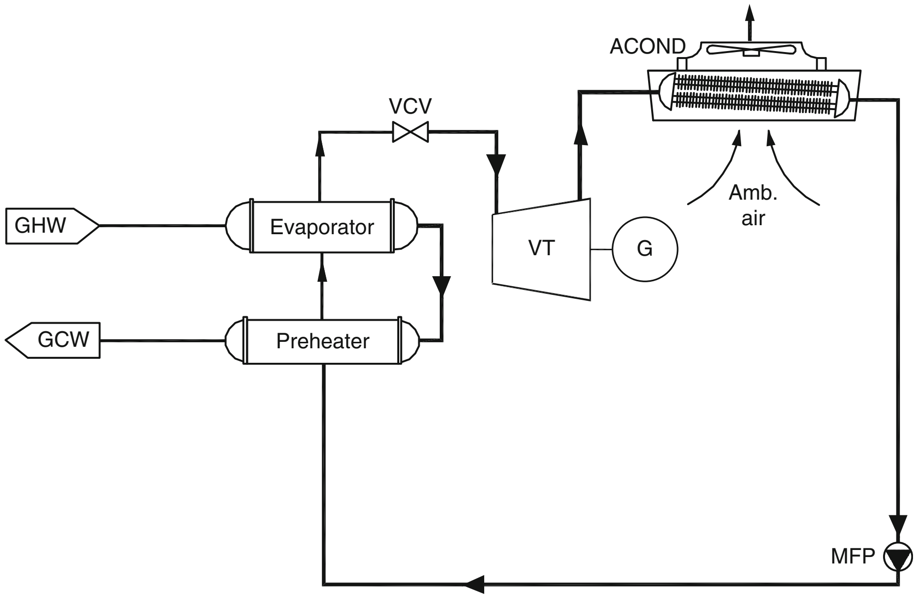
$$\dot{m}_{\mathrm{cair}} = \dot{m}_{\mathrm{wf}} \frac{(h_2 - h_3)}{Cp_{\mathrm{air}}(T_{\mathrm{airout}} - T_{\mathrm{airin}})} \tag{48}$$

Preheater and Evaporator Analysis Heat transfer to the working fluid takes place between points 4 and 1 in Fig. 20. Firstly, there is preheating between points 4 and 5, followed by evaporation up to point 1.

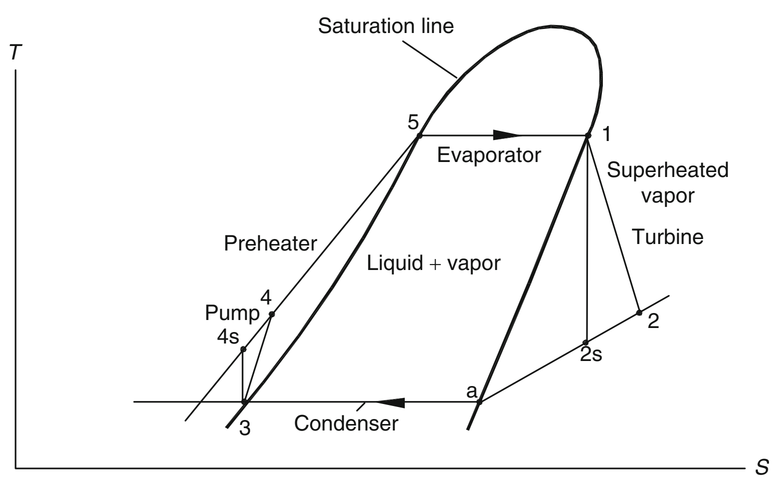
Secondly, on the brine side there is a continuous cooling due to the heat transfer to the organic fluid. Viewing the entire package as the thermodynamic system, the prevailing equation is:

$$\dot{m}_{\mathrm{b}}(h_{\mathrm{a}} - h_{\mathrm{c}}) = \dot{m}_{\mathrm{wf}}(h_1 - h_4) \tag{49}$$

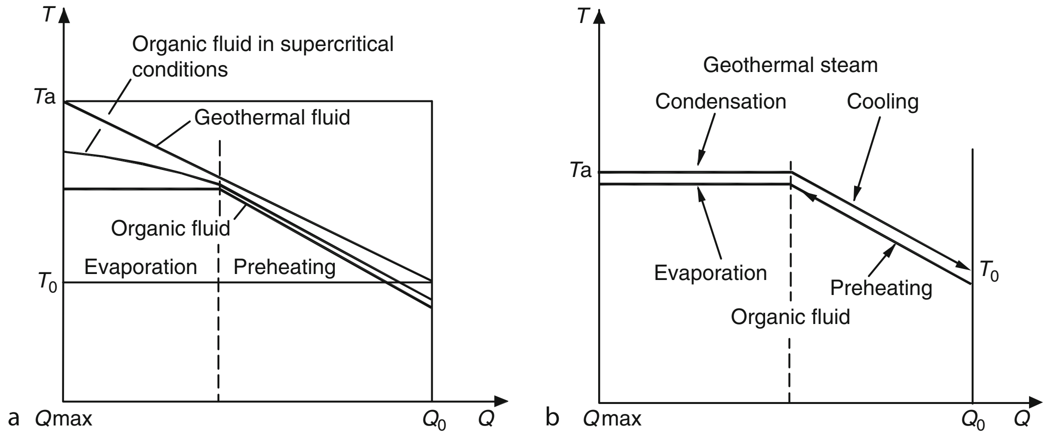
If the brine is considered as liquid only, then the left-hand side of the equation can be replaced by the



Geothermal Power Conversion Technology. Figure 19
Simplified schematic of an air-cooled binary geothermal power station [36]



Geothermal Power Conversion Technology. Figure 20
T-S diagram showing a basic Organic Rankine cycle



Geothermal Power Conversion Technology. Figure 21
T-Q diagrams of Organic Rankine cycle operated by (**a**) liquid and (**b**) geothermal steam

average specific heat of the brine $\bar{c}_b$ multiplied with the temperature drop:

$$\dot{m}_b \bar{c}_b (T_a - T_c) = \dot{m}_{wf}(h_1 - h_4) \tag{50}$$

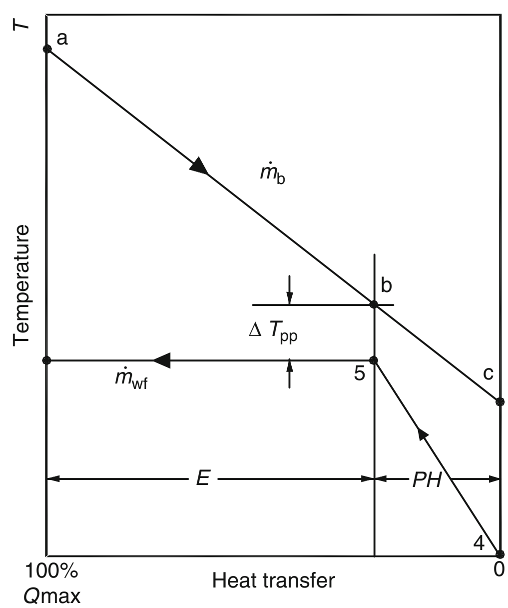
The following equation can be used to find the required brine flow rate for a given set of cycle design parameters:

$$\dot{m}_b = \dot{m}_{wf} \frac{h_1 - h_4}{\bar{c}_b (T_a - T_c)} \tag{51}$$

The total energy transfer between the brine and the organic vapor takes place between clearly between points 4 and 1 shown in Fig. 22. This data is required for the design of the individual heat exchangers. The abscissa represents the total amount of heat passed from the brine to the working fluid and can be presented either in percent or in total heat flow per unit time (kJ/h).

The preheater provides sensible heat to raise the working fluid to its boiling point, state 5. The evaporation occurs from 5 to 1 along an isotherm for a pure working fluid. The point in the heat exchanger where the brine and the working fluid experience the minimum temperature difference is called the pinch-point and is designated the pinch-point temperature difference ΔT_{pp} (see Fig. 22).

State points 4, 5, and 1 should be known from the cycle specifications. State 4 has the values of the compressed liquid at the outlet from the feed pump, state 5 is a saturated liquid at the boiler pressure, state 1 is a saturated vapor (same as at the turbine inlet condition). The geoliquid transfers heat to the evaporator from point a to point b, with the rest in the preheater



Geothermal Power Conversion Technology. Figure 22
Temperature-heat transfer diagram for preheater and evaporator

down to point c. The two heat exchangers may be analyzed separately as follows:

$$\text{Preheater}: \quad \dot{m}_b \bar{c}_b (T_b - T_c) = \dot{m}_{wf}(h_5 - h_4) \tag{52}$$

$$\text{Evaporator}: \quad \dot{m}_b \bar{c}_b (T_a - T_b) = \dot{m}_{wf}(h_1 - h_5) \tag{53}$$

The brine inlet temperature T_a is always known. The pinch-point temperature difference is known from manufacturer's specifications. This allows T_b to be determined from the known value for T_5.

The evaporator heat transfer surface is between the two fluids A_E, and can be determined from the basic heat transfer relationship:

$$Q_E = \bar{U} A_E LMTD|_E \tag{54}$$

where $\bar{U}$ is the overall heat transfer coefficient and $LMTD|_E$ is the log mean temperature difference.

For detailed calculations see DiPippo [33].

Since heat exchangers can be built in a variety of geometrical arrangements (shell-and-tube, plate, parallel flow, counter flow, etc.), there are correction factors to be used with the equations given above depending on the configuration. Refer to [37], for more details.

Overall Cycle Analysis Organic Rankine cycle performance can be assessed by the First Law using the thermal efficiency:

$$\eta_{th} \equiv \frac{\dot{W}_{net}}{\dot{Q}_{PH+E}} \tag{55}$$

Since the net power of the cycle is the difference between the thermal power input and the rejected thermal energy, this formula can be rewritten as:

$$\eta_{th} = \frac{\dot{Q}_{PH+E} - \dot{Q}_t}{\dot{Q}_{PH+E}} = 1 - \frac{\dot{Q}_c}{\dot{Q}_{PH+E}} = 1 - \frac{h_2 - h_3}{h_1 - h_4} \tag{56}$$

ORC efficiency is low because of low source temperatures and after subtracting all the parasitic loads from the gross power output, the final cycle efficiency may result in about 10%.

Another measure of station performance can be obtained using the Second Law in the form of the utilization efficiency η_u, which is defined (see Eq. 38) as the ratio of the actual net station power to the maximum theoretical power obtainable from the geothermal fluid in the reservoir state:

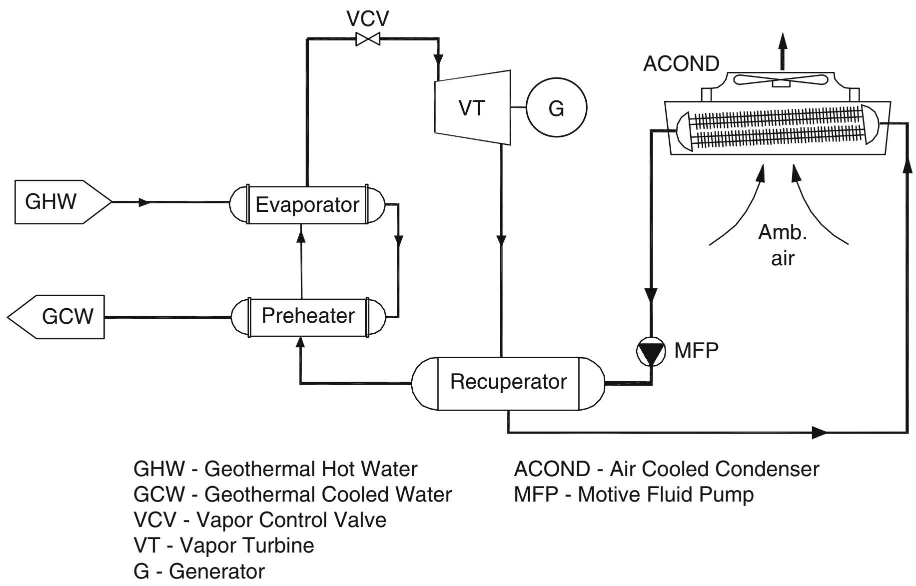
$$\eta_u = \frac{\dot{W}_{net}}{\dot{E}_{res}} = \frac{\dot{W}_{res}}{\dot{m}_b[(h_{res} - h_0) - T_0(s_{res} - s_0)]} \tag{57}$$

where $\dot{E}_{res}$ is $\dot{W}_{max}$ defined in the section on "Overall Thermal Efficiency," T_0 is the dead-state temperature (the local wet-bulb temperature if a water cooling tower is used), h_0 and s_0 are the enthalpy and entropy values for the geothermal fluid evaluated at the dead-state pressure and temperature (usually approximated as the saturated liquid values at T_0).

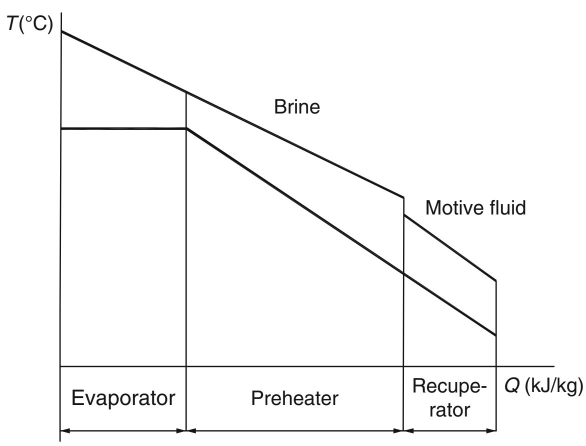
Recuperated Organic Rankine Cycle The efficiency of the Organic Rankine cycle described in the section on "Organic Rankine Cycle–based Power Generation Process" can be improved by recovering part of the heat of the superheated vapor before it enters the condenser (T_2 to T_a in Fig. 20) [53]. This is particularly important when there is limitation in the cooling temperature of the brine and condensate mixture. The silica scaling risk is the limiting factor in most of cases. It is increased as the brine temperature drops. In this case, the recuperator provides some of the preheating heat from the vapor, exiting the turbine.

The recuperator is applicable when the organic fluid is of the "dry expansion" type, where the expansion in the turbine is done in the dry superheated zone and the expanded vapor contains heat that has to be extracted prior to the condensing stage (Figs. 23 and 24). The recuperated Organic Rankine cycle is typically 10–15% more efficient than the simple Organic Rankine cycle described at the beginning of this chapter). This applies also to the two-phase geothermal power station as given in Figs. 25 and 26.

Temperature Cascading Organic Rankine Cycle A cascading system can be used to increase the power output of a binary power station [43]. In a simple cascading method there are two or more evaporators and preheaters, arranged in consecutive structure. The geothermal fluid travels from one pair of units to the other. The station incorporates three sets of organic systems, each working in different ranges of temperatures. In an improved cascading design, the evaporators are arranged in series while the preheaters



Geothermal Power Conversion Technology. Figure 23
Recuperated Organic Rankine cycle in simple binary power station – schematic



Geothermal Power Conversion Technology. Figure 24
Recuperated Organic Rankine cycle in simple binary power station

all work in the same temperature range [38]. Schematic design is given in Fig. 27.

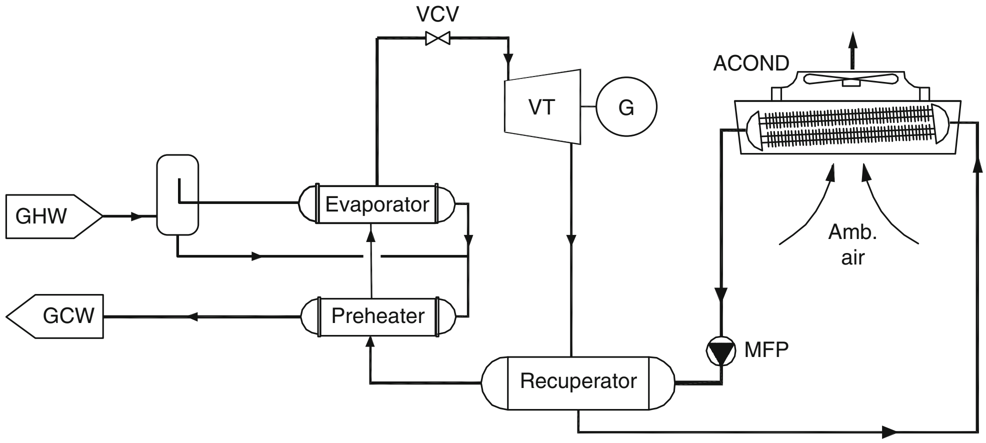
The T-Q diagram describing this combination is in Fig. 28. Since evaporation is performed at three different temperatures, three turbines are required for such an operation.

Dual-Pressure Organic Rankine Cycle A dual-pressure cycle is designed to reduce the thermodynamic losses incurred in the brine heat exchangers of the basic cycle. These losses are due to the transferring heat across a large temperature difference between the hotter brine and the cooler working fluid, see Fig. 29. By maintaining a closer match between the brine cooling curve and the working fluid heating/boiling curve, these losses can be reduced.

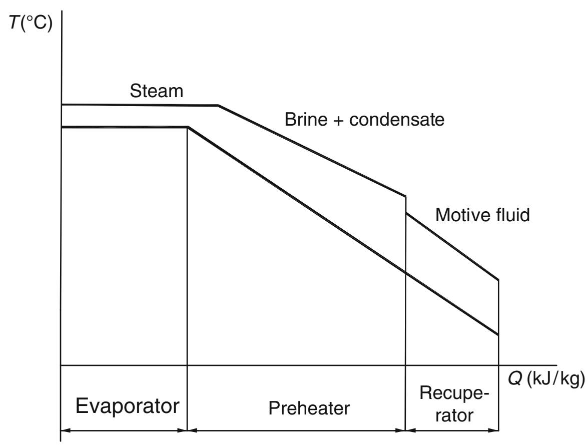
The dual-pressure cycle has a two-stage heating/boiling process that allows the two fluids to achieve a smaller average temperature difference than the one-stage process used in a basic cycle. A dual-pressure station schematic is given in Fig. 29 and the corresponding process diagram is shown in Fig. 30.

A dual-admission turbine is required to allow low-pressure saturated vapor (state 9) to be admitted to the turbine to mix with the partially expanded high-pressure vapor (state 2) to form a slightly superheated vapor (state 3). Given the small size of turbines using organic working fluids, practical considerations may lead to an alternative design using two separate turbines.

The analysis of a dual-pressure cycle follows the same methodology as a basic cycle but takes more time.



Geothermal Power Conversion Technology. Figure 25
Recuperated ORC in two-phase binary power station – schematic



Geothermal Power Conversion Technology. Figure 26
Recuperated ORC in two-phase binary power station

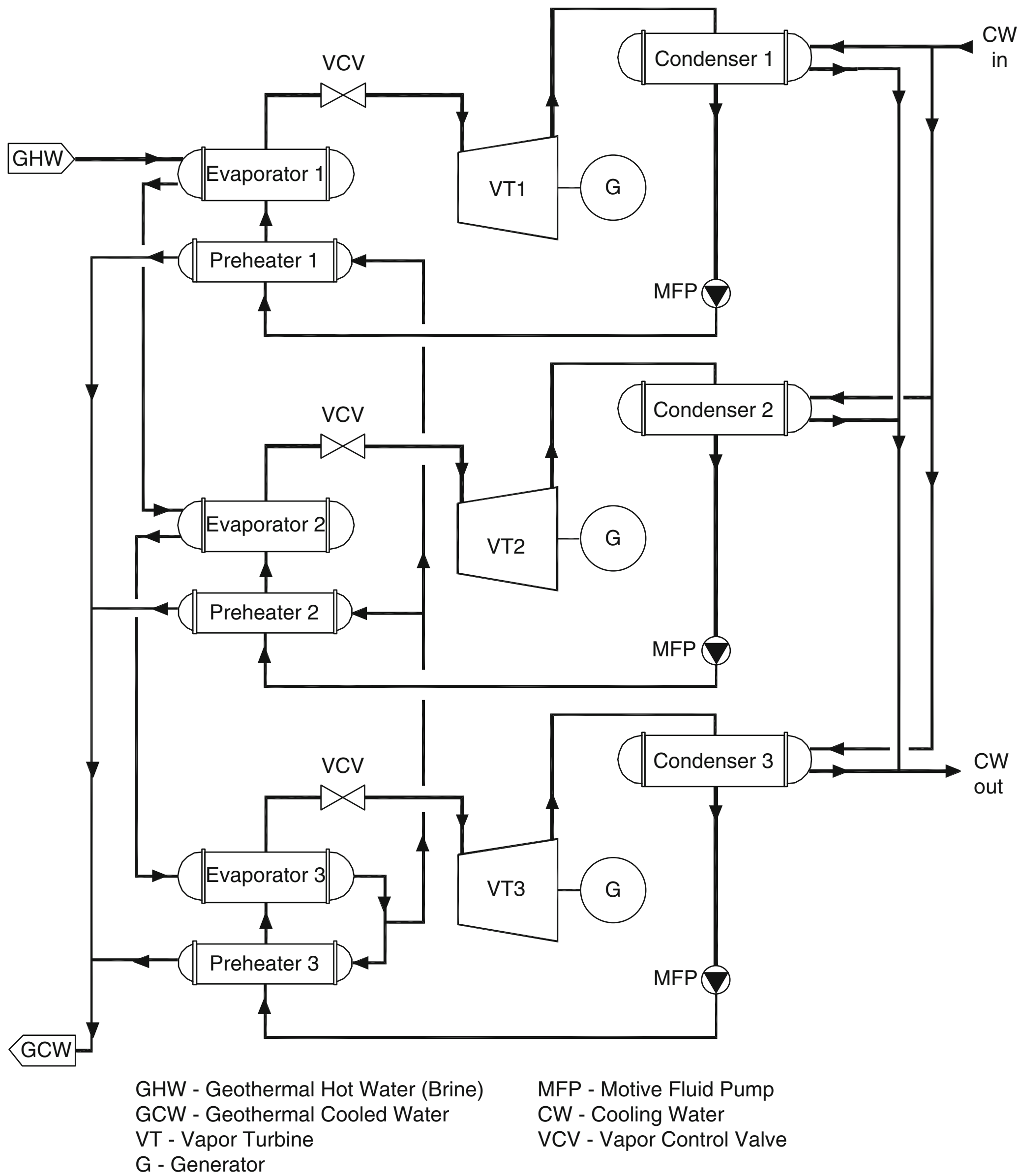
A detailed comparison of basic cycles (single-pressure) and the dual-pressure cycles was conducted by Khalifa and Rhodes [39] for two different working fluids. Their results show that in all cases, the thermal efficiency for a dual-pressure cycle is lower than for a basic cycle. However, the utilization efficiency for a dual-pressure cycle is significantly higher than for a basic cycle, ranging from a 6% advantage at the highest brine temperature to 24% advantage at the lowest.

The explanation for this is that thermal efficiency depends on the amount of heat added to the cycle but makes no distinction between resources maximum energy, ignoring the temperature difference between the fluids.

However, the utilization efficiency depends on how effectively the energy of the brine is used. By more closely matching the brine cooling curve to the heating and boiling curves, the average temperature difference between the two fluids is decreased and the irreversiblities are reduced. This allows more energy from the brine to enter the cycle leading to a higher overall utilization efficiency.

The 5 MW Raft River Dual-Boiling station in Idaho, USA, was the first to make use of the dual-pressure concept [40] and was operated as a demonstration station from 1981 to 1982 by the Idaho National Engineering Laboratory for the US Department of Energy.

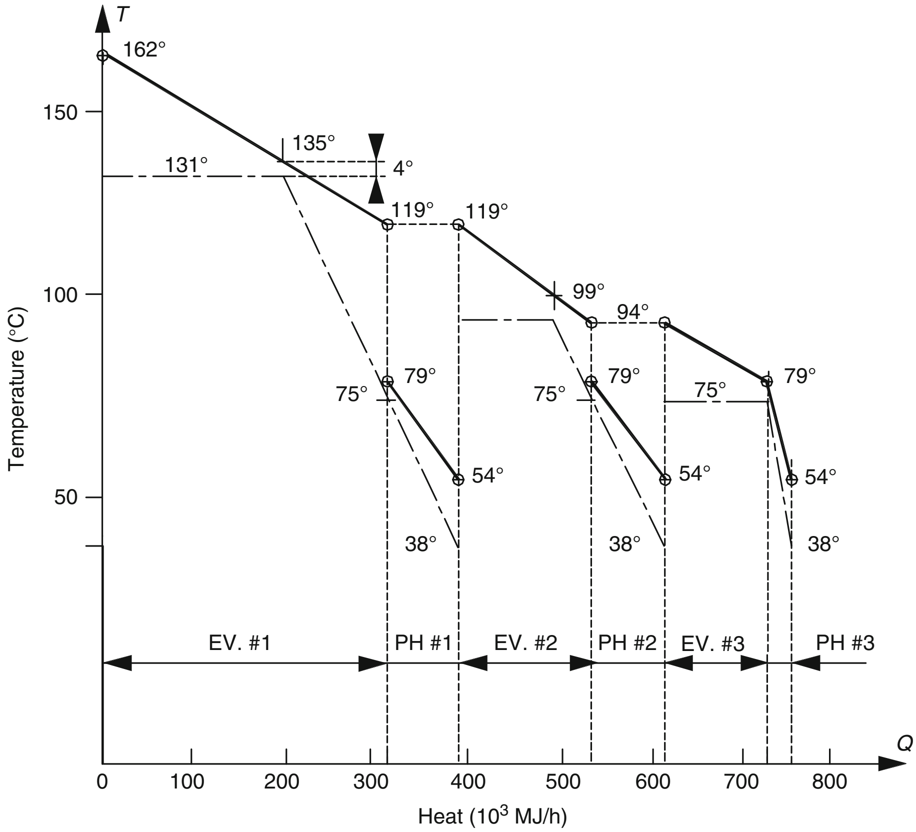
Supercritical Organic Rankine Cycles As mentioned in section on "Geothermal Resources" and shown in Fig. 21a, an Organic Rankine Cycle where the operating liquid in the supercritical zone follows



Geothermal Power Conversion Technology. Figure 27
Cascading ORC schematics

the heat source cooling curve more closely and the irreversibility losses of heat transfer are reduced as discussed by discussed by Tester and Milora [41] in detail. Four different cycles were examined. The operating fluid selected to illustrate the process is R-115 (C_2ClF_5) having a critical temperature of 80°C and being a suitable working fluid for both subcritical and supercritical operation at a geothermal fluid temperature of 150°C. In all four cases, the vapor was heated to 135°C and condensed at 26.7°C.

The first cycle is performed at 27.5 bar, i.e., subcritical cycle. The cycle efficiency is 9%, utilization efficiency is 46.5% and feed pump pressure ratio is 0.87. There is a quite large temperature gap between the cooling line of the geothermal fluid and the heated fluid. To improve the heat transfer, the second cycle pressure was increased



Geothermal Power Conversion Technology. Figure 28
T-Q diagram for cascading ORC

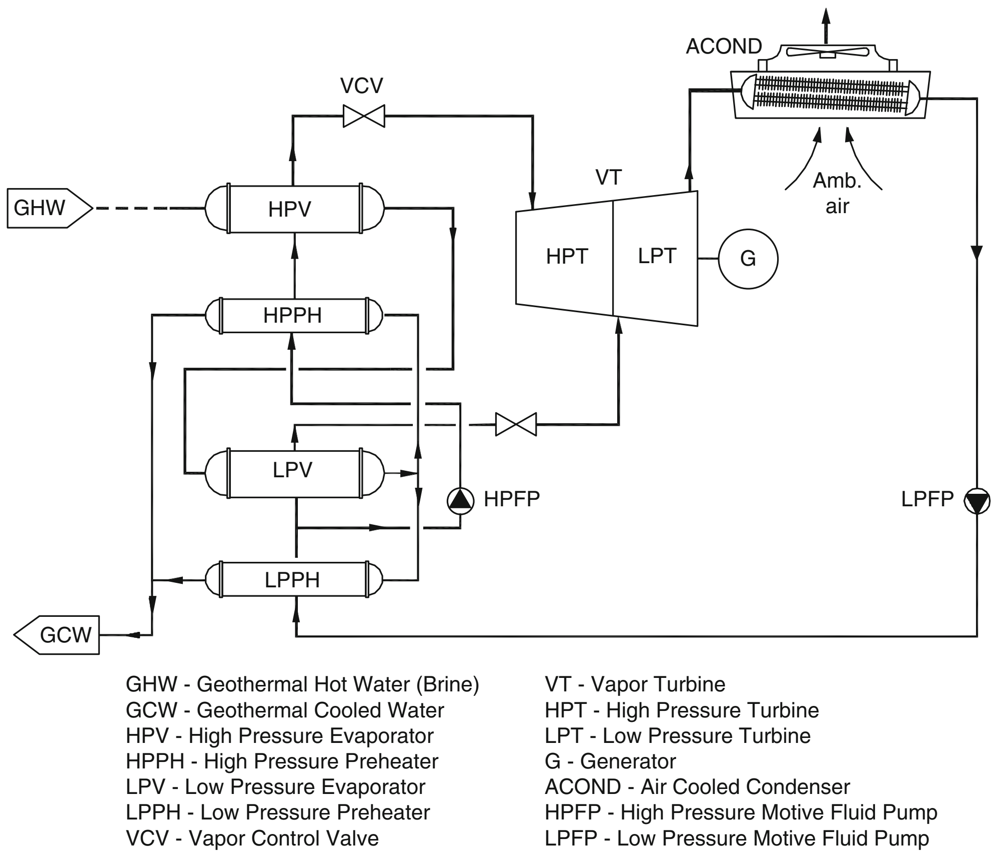
to 39.26 bar which is already in the supercritical zone. This increased the cycle efficiency to 11.2% and utilization efficiency to 56.5% but feed pump pressure ration increased to 1.24. Further increase of the pressure to 80 bar resulted in almost parallel cooling and heating lines. This increased both efficiencies to 11.9% and 63.2% respectively, and feed pump pressure ratio to 2.54. However, additional increase to 114.4 bar dropped cycle efficiency to 10.6% and utilization efficiency to 54.6%, feed pump pressure ratio to 3.62 and accompanied by expansion through the wet zone meaning a possible droplets impingement on the turbine blades.

In summary, the work at supercritical condition has improved the cycle and utilization efficiencies but simultaneously substantially increasing feed-pump work. There is a large pumping power requirement to nearly 50% of the net turbine power. Although the operation in 80 bar seems to achieve the highest cycle efficiency and highest utilization, the question of cost of an 80 bar structure and operation in high pressure against efficiency benefits will influence the final selection of operating conditions.

Nevertheless in more moderate conditions, supercritical cycles have been used, but the cycle efficiency improvement is impaired by the increased cycle pump losses. See the section on "Efficiency and Work Ratio."

Dual-Fluid Organic Rankine Cycle Experimental – see section on "Experimental Power Stations."

Working Fluid Selection Selection of the appropriate working fluid has great bearing on the performance of the Organic Rankine cycle. Considerations should include both thermodynamic properties of the fluids as well as health, safety, and environmental impact [51, 52].

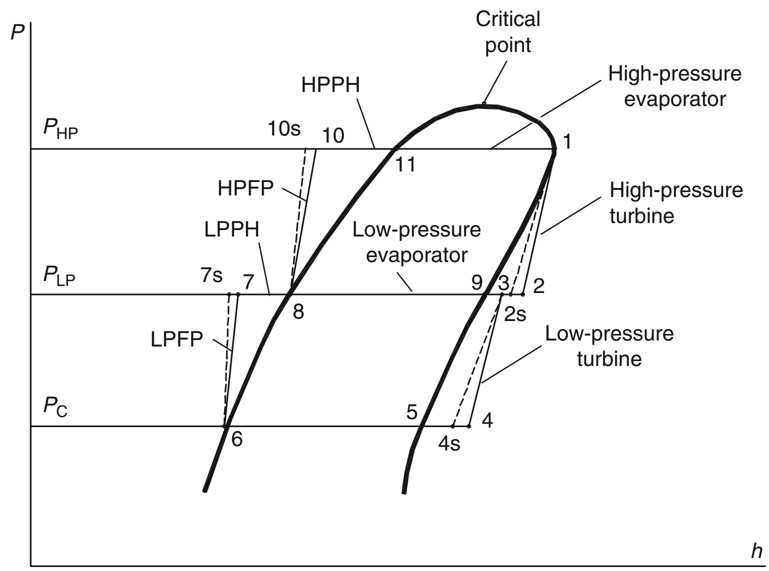


Geothermal Power Conversion Technology. Figure 29
Dual-pressure binary station based on single turbine with LP and HP inlets. Simplified flow diagram

Thermodynamic Properties Table 3 lists some candidate fluids and their relevant thermodynamic properties. Pure water is included for comparison [42]. Clearly all of the candidate fluids have critical temperatures and pressures far below water. Furthermore, since the critical pressures are reasonably low, it is feasible to consider supercritical cycles for the hydrocarbons. As already mentioned in "Supercritical Organic Rankine Cycles," this allows a better match between the brine cooling curve and the working fluid heating-boiling line, reducing the thermodynamic losses in the heat exchangers. However, the net power output may not be higher resulting from the high pumping energy required by the supercritical cycle.

Mixtures of these fluids have been studied for use in geothermal binary stations. In particular, the thermodynamic properties of 90% – C_4H_{10} and 10% i-C_5H_{12} were determined by the National Bureau of Standards (predecessor of NIST) in Washington [43] when it was chosen as the working fluid for the Heber Binary Demonstration station in the 1980s [44]. Mixtures evaporate and condense at variable temperature, unlike pure fluids that change phase at constant temperature. This means that subcritical pressure boilers for mixed fluids can be better matched to the brine curves, similar to, but not exactly like supercritical pure fluids. A practical hurdle in the use of water ammonia (Kalina cycle) mixture is that the differential leaks of the two fluids in various points of the system modify mixture composition over time.

Another important characteristic of candidate fluids is the shape of the saturated vapor curve as viewed in temperature–entropy coordinates, see Fig. 31. This curve for water (thin line) has a negative slope, but certain hydrocarbons and refrigerants show



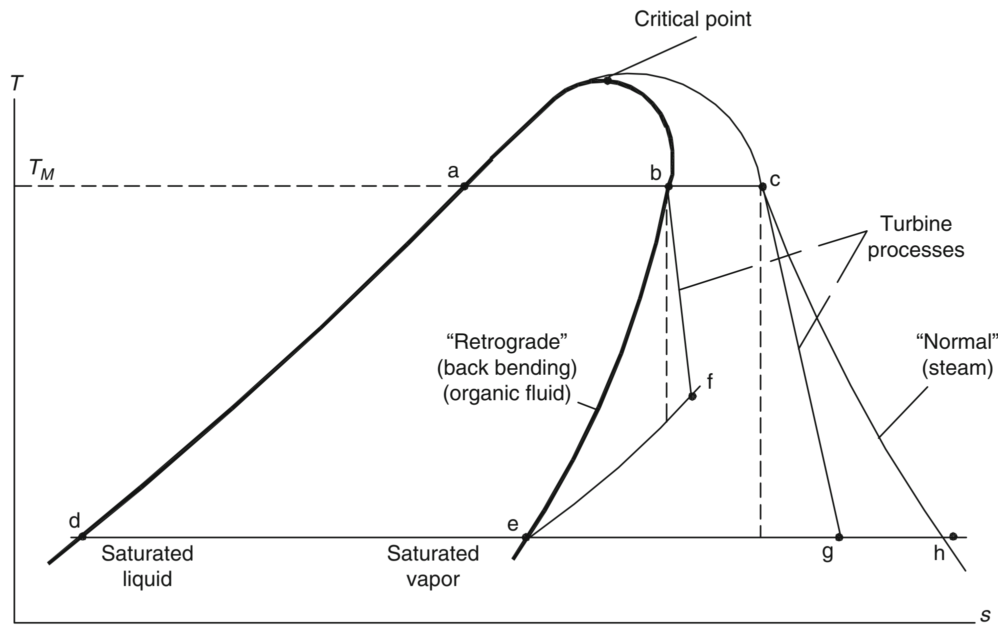
Geothermal Power Conversion Technology. Figure 30
Pressure–Enthalpy (P-h) diagram of a dual-pressure binary station

Geothermal Power Conversion Technology. Table 3 Thermodynamic properties of some candidate working fluids for binary stations

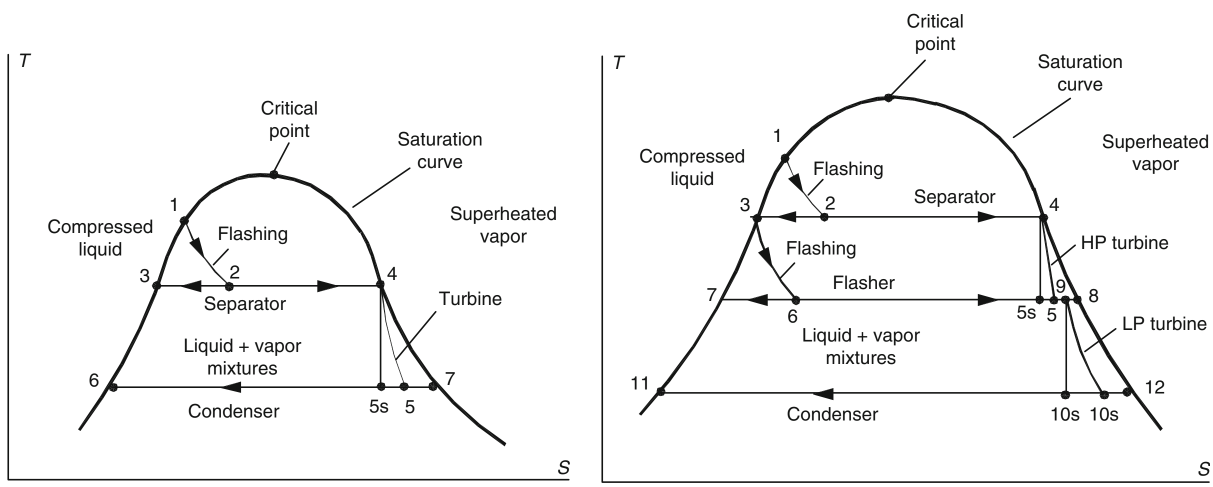
Fluid	Formula	T_c (°C)	P_c (MPa)	P_c (Lbf/in^2)	P_s@ 300 K (MPa)	P_s@ 400 K (MPa)
Propane	C_3H_8	96.95	4.236	614.4	0.9935	n.a.
i-Butane	i-C_4H_{10}	135.92	3.685	534.4	0.3727	3.204
n-Butane	C_4H_{10}	150.8	3.718	539.2	0.2559	2.488
i-Pentane	i-C_5H_{12}	187.8	3.409	494.4	0.09759	1.238
n-Pentane	C_5H_{12}	193.9	3.240	469.9	0.07376	1.036
Ammonia	NH_3	133.65	11.627	1,686.3	1.061	10.3
Water	H_2O	374.14	705.45	3,203.6	0.003536	0.24559

a positive slope for portions of the saturation line. That is, a local minimum in the entropy at some low temperature exists, T_m, and local maximum in entropy at higher temperature, T_M. Retrograde fluids include normal and iso-butane, normal and iso-pentane. These fluids exhibit retrograde behavior over the following temperature ranges, $T_m \rightarrow T_M$. C_4H_{10}, $-3°C \rightarrow 127°C$; i-C_4H_{10}, $-3°C \rightarrow 117°C$; C_5H_{12}, $-3°C \rightarrow 177°C$; and i-C_5H_{12}, $-13°C \rightarrow 177°C$. Since T_m is lower than any temperatures encountered in geothermal binary stations, these fluids can be taken as having saturated vapor lines similar to that shown in Fig. 32 for pratical purposes. This has major implications for Rankine cycles.

On the one hand, normal fluids such as water require considerable superheating, extending the isobar a–b–c upward to avoid excessive moisture at the turbine exhaust, state g. On the other hand, retrograde (backbend) fluids allow expansion from the saturated vapor line into the superheated region, process b–f, avoiding any moisture during the turbine expansion process. It has been shown [45] that it is possible to run



Geothermal Power Conversion Technology. Figure 31
Temperature-entropy diagram contrasting normal and retrograde saturated vapor curves



Geothermal Power Conversion Technology. Figure 32
T-S diagrams for single (*left*) and double-flash (*right*) steam cycles

a supercritical cycle where the turbine inlet state lies above the critical point and the expansion line lies inside the wet region for a portion of the process, emerging into the superheated region, without suffering any wetness penalty in efficiency. Apparently, the fluid remains in a metastable vapor state while passing through the wet region by staying on the dry side of the Wilson line [46].

Turbine Size While evaluating the potential working fluid, turbine size and cost must also be considered as part of that task. Milora and Tester [47] compared a line

of hydrocarbons that are suitable for use in binary systems (including steam for comparison) on the basis of nondimensional turbine design parameters. They used four basic parameters: turbine blade diameter, turbine rotational speed, enthalpy drop, and volumetric flow rate. Using the factors that build those parameters, they established a "figure of merit" that is influenced by the fluid molecular weight, heat of evaporation (h_{fg}), specific volume, critical pressure, etc. Additional evaluation was made on the exit flow area that is also influenced by the same factors as shown by them [47] and also by DiPippo [33]. The results of both evaluations show that for the same power output and temperature range, systems that use low molecular weight fluids like ammonia (NH_3) result in a smaller turbine than butane or pentane by factors of 5 and 12 respectively, and for comparison smaller than steam turbine by factor of 120–150 times due to the large specific volume of steam in low temperatures. These general evaluations do not eliminate the need for particular turbine design for actual operating conditions.

Environmental Safety and Health Considerations The fluids used in the Organic Rankine cycle should comply with local and international health and environmental rules and agreements such as the Copenhagen Amendment of 1994 and Montreal Protocol of 1987 (in comparison with R-12 and R-114 that were banned from use and rated 1 for Ozone Depletion Potential (ODP)). Other potential fluids in Table 4 [48] are acceptable even though they are flammable. The table also compares Global Warming Potential which illustrates main reason for banning R-12 and R-114.

Ancillary Systems

Separation Process The separation process is considered as one at constant pressure, i.e., an isobaric process once the flash has taken place. The quality or dryness fraction, x, of the mixture that forms after the flash, state 2 (Fig. 32), can be found from:

$$x_2 = \frac{h_2 - h_3}{h_4 - h_3} = \frac{h_1 - h_3}{h_4 - h_3} = \frac{h_1 - h_3}{h_{fg}(T_3, P_3)} \tag{58}$$

(h_{fg} is latent heat of evaporation (B)) by using the "lever" rule between points 3 and 4, the steam mass fraction of the mixture can be found. It specifies the amount of steam flowing to the turbine per unit total mass of flow into the separator.

For the expansion, condensing and cycle analysis refer to the section on "Expansion Process."

Geothermal Power Conversion Technology. Table 4 Environmental and health properties of some candidate working fluids [41]

Fluid	Formula	Toxicity	Flammability	ODP	GWP
R-11	CCl_3F	Nontoxic	Non-flam	1.0	4,000
R-12	CCl_2F_2	Nontoxic	Non-flam	1.0	4,500
R-113	CCl_3CF_3	Nontoxic	Non-flam	0.8	4,800
R-114	$C_2Cl_2F_4$	Nontoxic	Non-flam	0.7	5,850
Propane	C_3H_8	Low	Very high	0	3
i-Butane	$i\text{-}C_4H_{10}$	Low	Very high	0	3
n-Butane	C_4H_{10}	Low	Very high	0	3
i-Pentane	$i\text{-}C_5H_{12}$	Low	Very high	0	3
n-Pentane	C_5H_{12}	Low	Very high	0	3
Ammonia	NH_3	Toxic	Lower	0	0
Water	H_2O	Nontoxic	Non-flam	0	–
R245fa	$CF_3CH_2CHF_2$	Nontoxic	Non-flam	0	950

Flashing Process The sequence of processes begins with geothermal fluid under pressure at state 1, close to the saturation curve. The flashing process is modeled as one at constant enthalpy, or isenthalpic process as it occurs steadily, spontaneously, essentially adiabatically, and with no work involvement also ignoring any change in the kinetic or potential energy of the fluid as it undergoes the flash, therefore:

$$h = \text{constant} \tag{59}$$

Flash and Separation Processes Referring to Fig. 32b, the two flash processes 1–2 and 3–6 are analyzed the same as the flash process for the single-flash station in Figs. 13 and 32a. Each process generates a fractional amount of steam given by the quality x, of the 2-phase mixture. Each flash is followed by a separation process. The governing equations are as follows:

$$h_1 = h_2 \tag{60}$$

$$x_2 = \frac{h_2 - h_3}{h_4 - h_3} \tag{61}$$

$$h_3 = h_6 \tag{62}$$

$$x_6 = \frac{h_3 - h_7}{h_8 - h_7} \tag{63}$$

The mass flow rates of the steam ($\dot{m}_{hps}$) and liquid (brine) ($\dot{m}_{hpb}$) for the high- and low-pressure stages are found from:

$$\dot{m}_{hps} = x_2 \dot{m}_{total} = \dot{m}_4 = \dot{m}_5 \tag{64}$$

$$\dot{m}_{hpb} = (1 - x_2)\dot{m}_{total} = \dot{m}_3 = \dot{m}_6 \tag{65}$$

$$\dot{m}_{lps} = (1 - x_2)x_6 \dot{m}_{total} = \dot{m}_8 \tag{66}$$

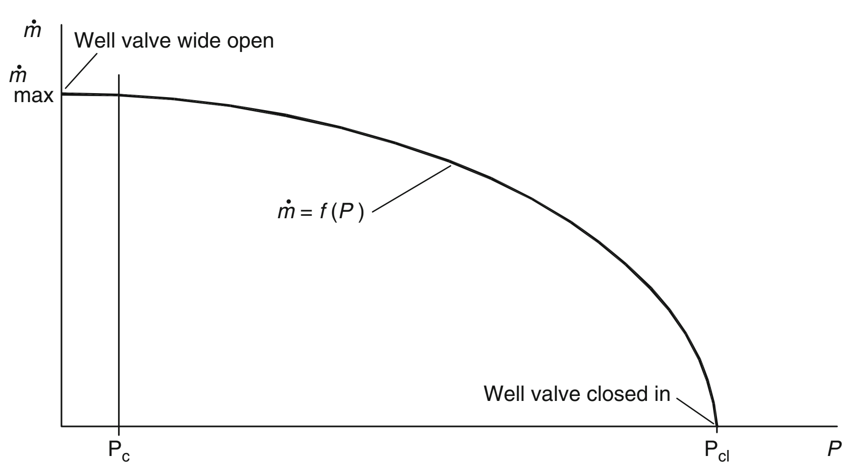
$$\dot{m}_{lpb} = (1 - x_2)(1 - x_6)\dot{m}_{total} = \dot{m}_7 \tag{67}$$

These mass flows will be used to calculate the power generated from the two stages of turbine expansion, the amount of waste liquid to be disposed of and the heat that must be rejected through the condenser and ultimately from the cooling tower.

Optimization

Optimum Wellhead Pressure Once a valve is installed on the well, the pressure at which the power station is to operate must be determined with the wellhead pressure being controlled by a throttling valve. The well productivity curve can be approximated as an elliptical equation in terms of the mass flow rate of steam as a function of the wellhead pressure:

$$\left[\frac{\dot{m}}{\dot{m}_{max}}\right]^2 + \left[\frac{P}{P_{ci}}\right]^2 = 1 \tag{68}$$



Geothermal Power Conversion Technology. Figure 33
Productivity curve for dry-steam wellhead

where $\dot{m}_{max}$ is the maximum observed mass flow rate at full open valve and P_{ci} is the closed-in wellhead pressure. This function is shown schematically in Fig. 33. Assuming that values for these two parameters are available from well tests, the mass flow rate at any pressure can be calculated by:

$$\dot{m} = \dot{m}_{max}\sqrt{1 - (P/P_{ci})^2} \tag{69}$$

Since opening the wellhead valve is a throttling process, the enthalpy of the steam remains the same.

Turbine power is proportional to the product of the steam mass flow rate and the enthalpy drop Δh (shown as an ideal isentropic process), from $h_{ci} = h_1$, down to assumed condenser pressure. The maximum is located somewhere in between.

Compute and solve for the power output per maximum steam flow rate by using Eqs. 15 and 69 as follows:

$$\frac{\dot{W}}{\dot{m}_{max}} = \frac{\dot{W}}{\dot{m}} \times \frac{\dot{m}}{\dot{m}_{max}} = (h_1 - h_2) \times \sqrt{1 - (P/P_{ci})^2} \tag{70}$$

where $(h_1 - h_2)$ is the isentropic enthalpy drop across the turbine (Δh in Fig. 34), that can be obtained graphically using a large-scale Mollier diagram, see *Steam Tables* [32].

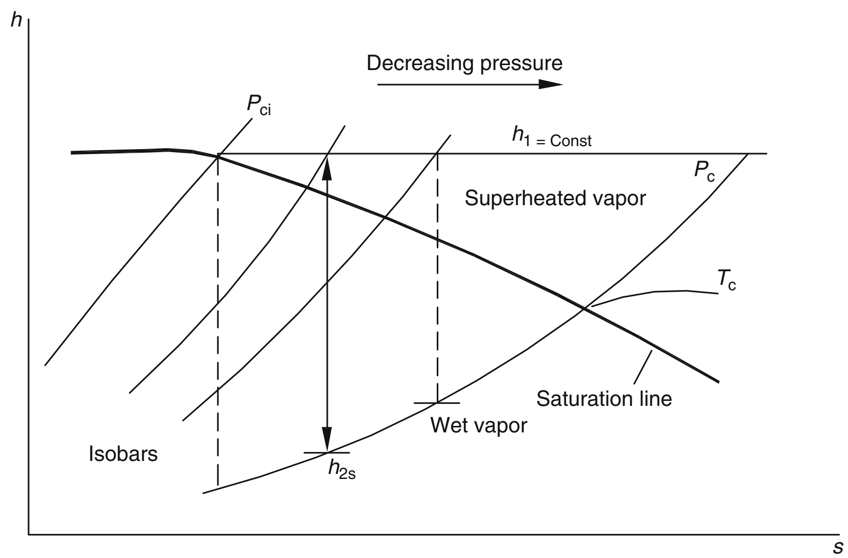
The work method involves preparing a table of Eq. 70 variables, i.e., h_1, h_2 (for given condenser pressure), $h_1 - h_2$, P/P_{ci} and $\frac{\dot{W}}{\dot{m}_{max}}$ as function of the pressure p changing between closed and open valve position.

DiPippo [33] solved this problem for a non-isentropic turbine for given wellhead data. The result has a parabolic shape with maximum at about 40% of the closed valve pressure.

It should be noted that the curve is relatively flat near the optimum point, i.e., the power output is within 0.2% of the optimum, over a wide range of wellhead pressures. This allows for a wide enough pressure/valve setup range without sacrificing much of the power generation.

The optimization process for a double-flash station is more complicated than for a single-flash station due to the extra degree of freedom in the choice of operating parameters. This results in two maxima, one of which yields the highest power output and the other that has the best specific power output. The results are not identical.

An example of a double-flash optimization was made by DiPippo [49] for the Electric Power Research Institute. The specific and total power outputs reach their respective maxima at different points. The variation results in different second flashing



Geothermal Power Conversion Technology. Figure 34
Expansion from variable wellhead pressures (constant enthalpy)

temperatures and a difference of 2.5% in the thermal utilization efficiency. However, in comparison with a single-flash station operating in the same conditions the double-flash generates about 31% more power.

If the rule of "equal temperature split" is used for initial evaluation, then the results for first and second flashing are close to the optimized calculations for maximum power and less accurate for maximum efficiency. This is acceptable for an approximation in view of the optimistic assumptions for the calculation that neglect pressure and thermal losses between the wellhead and the turbine.

Efficiency and Work Ratio The usual definition of thermal efficiency as the ratio between the net work done by the fluid and the total heat input to the cycle can be misleading in assessing the suitability of a given cycle in a heat engine. A concept of paramount importance in evaluating the suitability of a particular cycle for use in a heat engine is that of *work ratio*. This is defined as the ratio of the net work output of the cycle to the total positive (expansion) work of the cycle.

If there is very little negative work, as in a typical subcritical vapor cycle where only liquid of small specific volume has to be pumped at moderate pressure back into the boiler, the work ratio will be high. By contrast, this ratio is lower in a supercritical cycle where because of the high pressure, a larger portion of the positive work of the turbine is used to drive the feed pump [41].

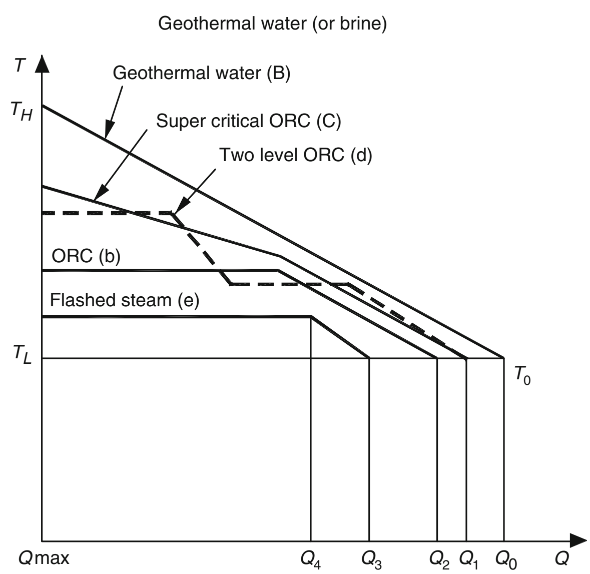
Taking all these practical implications of work ratio, it can be seen that the concept of work ratio into account, it can be seen that the concept of work ratio can be regarded as almost as important as the concept of ideal cycle efficiency in many ways. Refer to Table 5.

Optimizing the Efficiency by Matching the Cycle to the Heat Resource

Single-Phase Water or Brine Resource In Fig. 35, line (a) is a typical T-Q diagram showing the heat exchange between single phase water or brine geothermal fluid and Organic Rankine cycle fluid from the hydrocarbons family of materials. The geothermal fluid cools during the heat transfer operation while there are a few options for heat utilization by the Organic Rankine cycle fluid. The simple case is line (b) that comprises preheating and evaporation of the organic fluid. The optimal case would be a constant temperature difference between the two fluids. This is difficult to achieve, but is almost attained with Organic Rankine cycle fluid operation in a supercritical condition as show in line (c). However, the gain carries penalties. The first penalty is the large pumping power and the second is the high cost of hardware operating at such high pressures.

Geothermal Power Conversion Technology. Table 5
Comparison of work ratio in supercritical and subcritical ORC

	Supercritical ORC	Cascaded ORC
Gross (kW)	15,900	14,800
Fans (kW)	1,000	1,000
Feed Pump (kW)	2,450	900
Net	12,450	12,900
Work Ratio	78%	87%
For identical heat source and heat sink conditions:		
Heat source (liquid):		
Inlet temperature 170°C		
Outlet temperature 85°C		
Heat sink (air): 25°C		



Geothermal Power Conversion Technology. Figure 35
T-Q Diagram comparing of Organic and Flash Steam cycle for 160°C heat source

Another option is using the Organic Rankine cycle fluid under the saturation curve applying step heating with one or more evaporation stages – line (d) for two stages or as in a cascading system described in Fig. 35 which gives a better fit.

Figure 35 line (e) illustrates the differences in the temperature drop between a Flash Steam Rankine cycle and an Organic Rankine cycle. Because of the lower heat capacity of organic liquids and their much smaller latent heat of vaporization, these fluids lead to significantly smaller irreversibility losses of availability in the utilization of low or medium temperature predominantly sensible heat streams (Table 6).

Water-Dominated Two-Phase Flow When a substantial portion of the heat content of the geofluid is sensible heat of the liquid phase, the ORC has the advantage that its latent heat of evaporation is smaller than that of steam and therefore the vaporization temperature can be higher than that of a flash plant (Fig. 36). This leads to a higher efficiency and in addition eliminating the parasitic consumption of the condenser vacuum pumps.

Choked Well Flow The selection of separator operating conditions for liquid-dominated well has economical value. Optimization should be made for such evaluation. Two cases for choked and non-choked flows for liquid dominated wells are thoroughly studied by DiPippo [33, p. 98]. In his evaluation, two assumptions are made:

- There are no pressure losses between the wellhead and the turbine.
- Condensation occurs at certain known temperature (site specific).

As detailed in DePippo [33], the flow increases rapidly as the well is opened and the pressure is lowered. However, once the valve position is about 90% open (Fig. 37), the flow rate stabilizes and further opening of the well valve does not raise the total mass flow rate as the flow is “choked.”

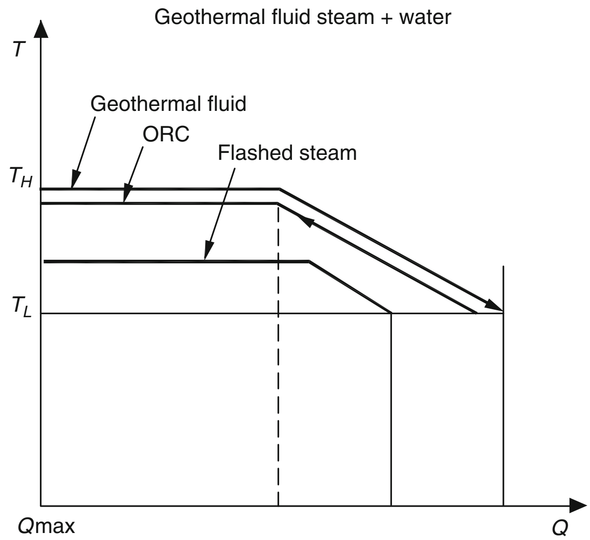
The question now is what wellhead pressure should be chosen to maximize the power output from a single-flash station connected to this well.

Eqs. 60–67 and 15–30 and a Mollier chart [32] are used to analyze the flashing, separation and turbine expansion processes. The calculations proceed in two phases:

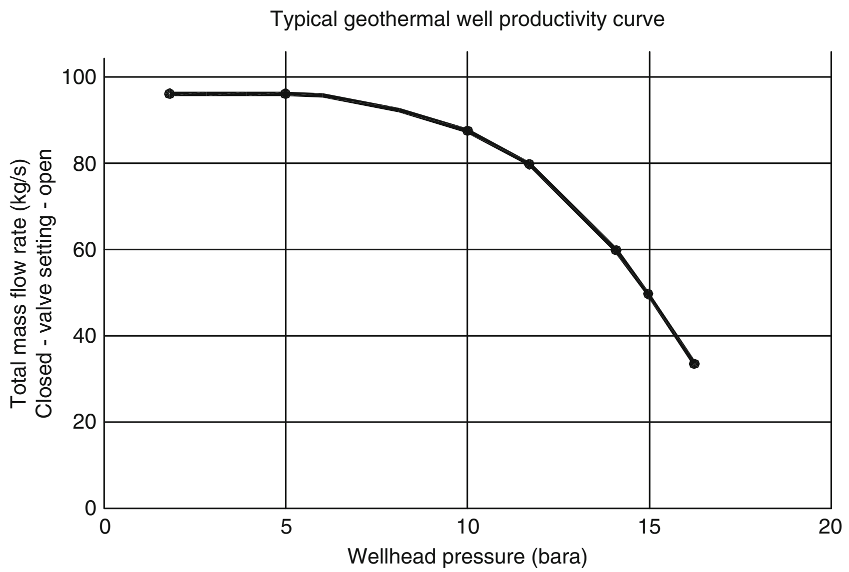
- Phase 1 to determine the specific power output (measured by enthalpy drop on the Mollier chart) for a range of separator pressures (and equivalently temperatures).

Geothermal Power Conversion Technology. Table 6
Comparison of power recovered by Ormat and Steam cycles for a 160°C heat source

Cycle comparison based on gross power		
	Steam	Organic
% preheat	9.6%	38%
Optimum Exit Temp	92.5	78
Heat Input	83%	100%
Thermal Efficiency (Gross)	10.7%	11.1%
Power (Gross)	80%	100%
Cycle comparison based on net power		
	Steam	Organic
% preheat	9.6%	38%
Optimum Exit Temp	92.5	78
Heat Input	83%	100%
Thermal Efficiency (Net)	10.6%	10.6%
Power (Net)	85%	100%



Geothermal Power Conversion Technology. Figure 36
T-Q diagram of binary cycle driven by geothermal steam



Geothermal Power Conversion Technology. Figure 37
Typical geothermal well productivity curve

- Phase 2 to find the total power by use of the variations of the total-flow rate as a function of the separator pressure.

Phase 1 calculations may rely on normal Steam Tables [31, 32] since the characteristics of the actual stream are unknown. Using the temperature and pressure of the maximum point, the actual flow rate is found from the productivity curve at that wellhead pressure. When this is multiplied by the corresponding specific power (Eq. 17) the maximum power can be obtained.

Non-Choked Well Flow Many wells do not have a near flat response nearing open valve position. This may be a result of the well bore diameter being to small. The well is characterized by the high slope production data curve as in Fig. 38 meaning a continuously increased flow rate with further opening of the valve on the wellhead.

The results of phase 1 calculations are the same as for the first case. The results of phase 2 calculations are such that the maximum specific power and maximum total power are not at the same temperature. The designer must select the best choice based on economical factors in a particular set of the wells.

An Approximate Formulation for Separation Temperature Along with the previous method described above, DiPippo [33] developed an approximate method that leads to an easy solution for T_3 which is:

$$T_{3,\mathrm{opt}} = \frac{T_1 + T_6}{2} \tag{71}$$

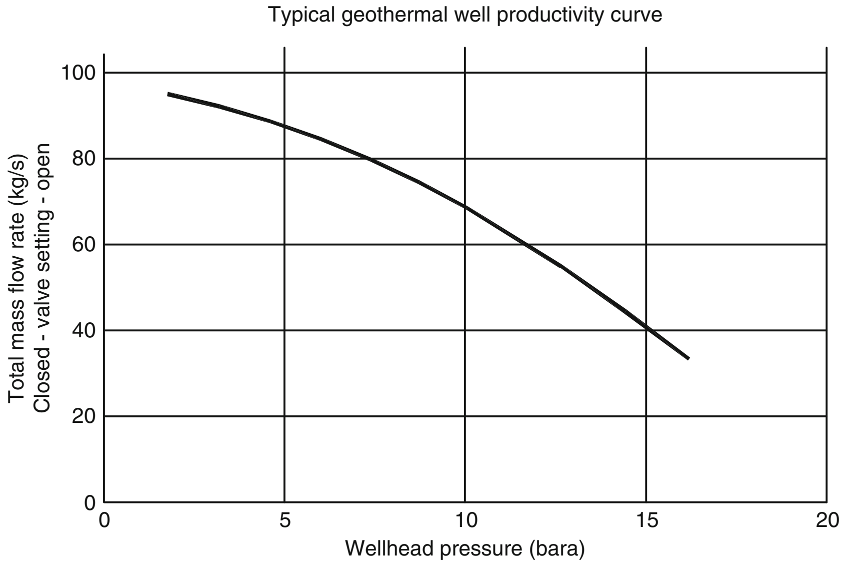
(T_1 is the inlet temperature and T_6 is the condenser temperature)

Since this rule indicates that the temperature range between the reservoir and the condenser is divided into two equal segments, this rule is sometimes called the “equal-temperature-split” rule. This approximate rule applies to all flash stations regardless of the number of flashing steps [50]. The rule is that the temperature difference between the reservoir and the first flash is equal to the temperature difference between the first flash and the second flash, as well as between the second flash and the condenser.

Main Power Station Components

Steam Turbines

General Turbines used in geothermal applications are made of corrosion-resistant materials due to the presence of gases such as hydrogen sulfide which



Geothermal Power Conversion Technology. Figure 38
Typical geothermal well productivity curve

induce stress corrosion and erosion due to droplets and entrained solids.

A dry-steam power station utilizes similar turbines as those used in a fossil fuel power station (Fig. 39).

The turbines are single-pressure units with impulse-reaction blades, either single-flow for smaller units or double-flow for large units above 50 MW as in Fig. 40. The condensers can be either direct-contact (barometric or low-level) or surface-type (shell-and-tube).

Direct Exhaust Steam Turbine Large turbines usually sit over the direct contact condenser maintaining minimum pressure losses at the turbine exit. For small units it is often advantageous to arrange the turbine and condenser side by side, for maintenance reasons.

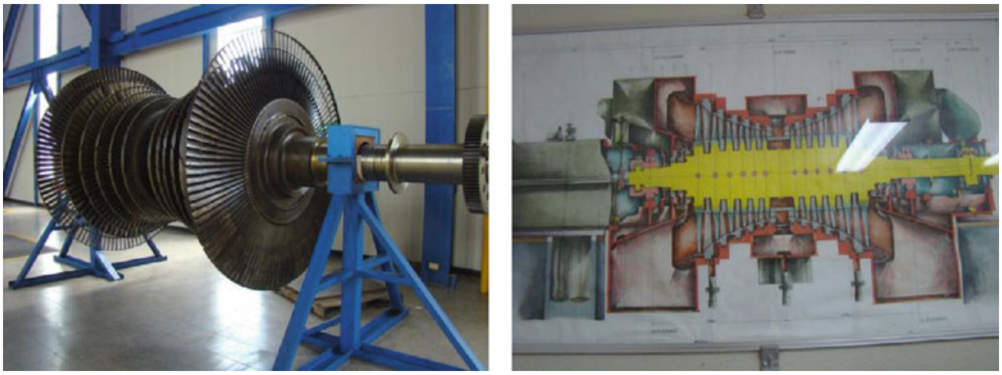
Turbines for Dry Steam or Single Flash A typical power station flow diagram is detailed in Fig. 41. At each production well (PW), there is equipment to control and monitor geothermal fluid flow from the well to the station. This equipment includes:

- Wellhead valve – WV
- Silencer or rock muffler – S or RM
- Particle remover/purifier – PU

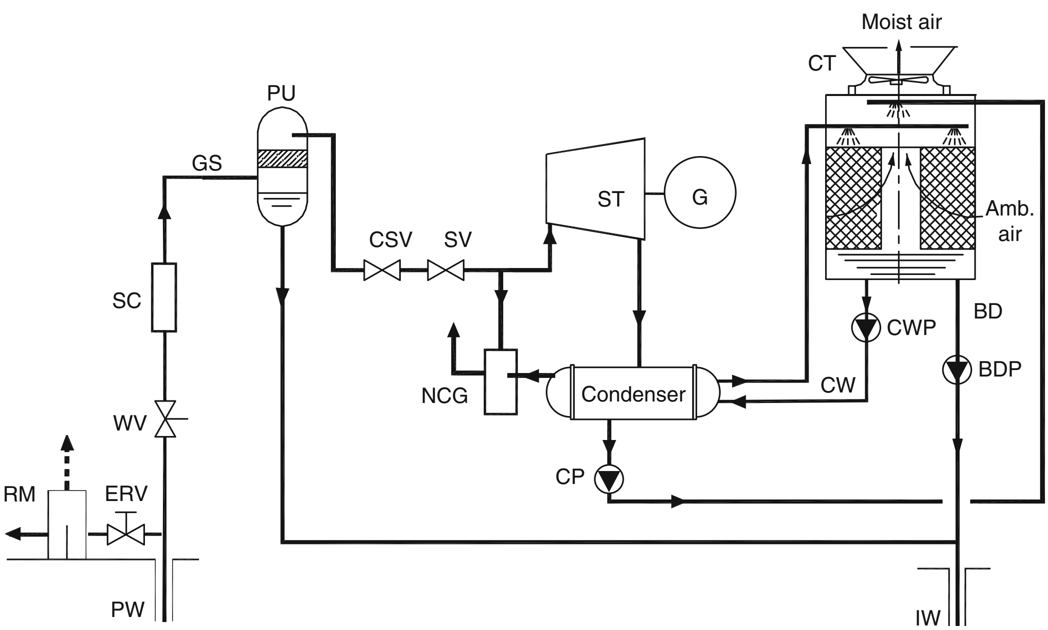
Geothermal Power Conversion Technology. Figure 39
Dry Steam 35 MW Franco Tossi turbine in Costa Rica (Courtesy of ICE, Costa Rica)

- Emergency relief valve – ERV
- Piping and instrumentation (pressure and temperature gauges)

If wellhead separators are used, the cyclone separator, CS is located close to the wellhead on the same pad. Also note that the NCG disposal used in the example below is of the steam ejector type.

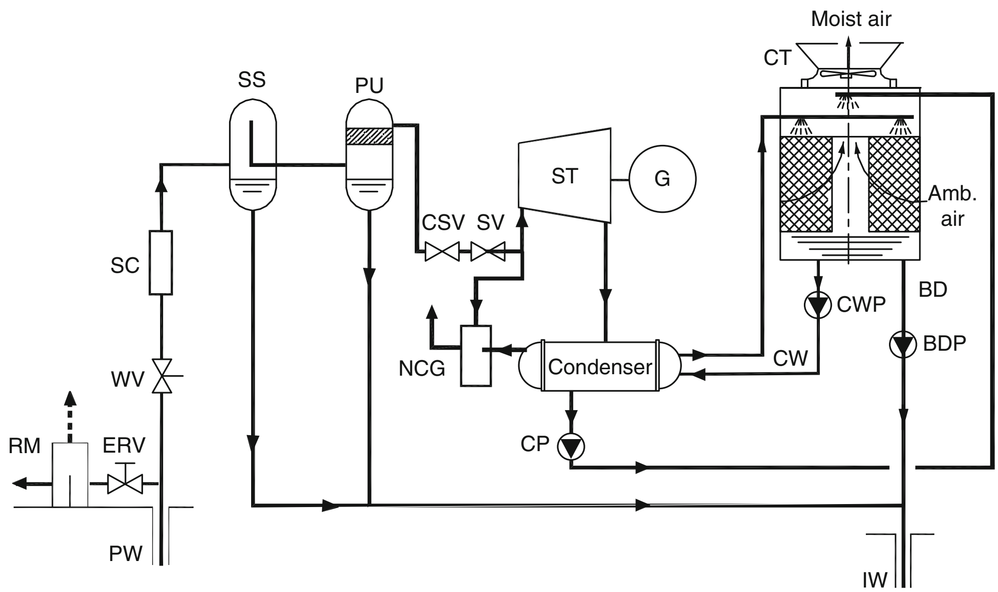


Geothermal Power Conversion Technology. Figure 40
A double-flow turbine rotor and cross section of a double-flow dual-admission steam turbine (Courtesy of ICE Costa Rica)



PW - Production Well
IW - Injection Well
GS - Steam
PU - Purifier
CSV - Control Valve
RM - Rock Muffler
WV - Wellhead Valve
SC - Scrubber
ST - Steam Turbine
G - Generator
CT - Cooling Tower
CP - Condensate Pump
CWP - Cooling Water Pump
CW - Cooling Water
SW - Spent Water
BD - Blow Down
BDP - Blow Down Pump
NCG - Non Condensable Gas Disposal (steam ejector type)
SV - Stop Valve

Geothermal Power Conversion Technology. Figure 41
Simplified scheme of a dry-steam power station



PW - Production Well
IW - Injection Well
PU - Purifier
CSV - Control Valve
RM - Rock Muffler
WV - Wellhead Valve
SC - Scrubber
RV - Release Valve
SS - Steam Separator

G - Generator
ST - Steam turbine
CT - Cooling Tower
CP - Condensate Pump
CWP - Cooling Water Pump
CW - Cooling Water
BD - Blow Down
SV - Stop Valve

BDP - Blow Down Pump
NCG - Non Condensable Gas Disposal

Geothermal Power Conversion Technology. Figure 42
Simplified single-flash power station schematic [56]

The single-flash steam power station is the most common geothermal power industry system. DiPippo states [33] that as of May 2007, there were 159 units of this kind in operation in 18 countries around the world with single-flash stations accounting for about 32% of all geothermal stations, constituting over 42% of the total installed geothermal power capacity in the world. The unit power capacity ranges from 3 to 90 MW, and the average power rating is 25.3 MW per unit.

Turbines for single-flash units are typically rated at 25–50 MW and consist of 4–5 stages of impulse-reaction blades. Both single and double-flow designs are in use. Overall isentropic efficiencies in the high 80% range have been obtained.

For the thermodynamic analysis of the energy conversion process, it is assumed that the geothermal fluid starts as a compressed liquid somewhere in the reservoir. It experiences a flashing process separating the two phases in the cyclone separator. The steam is used to drive a turbine (Fig. 42) and the brine sent for well reinjection [35].

A classic example of a wellhead arrangement showing the valves and separator is given in Fig. 43.

The steam from the turbine is condensed by means of either a surface-type condenser (C), as shown in Figs. 16a and 42, or in a direct-contact condenser of either the barometric or low-level type, Fig. 16b.

Turbines for Double-Flash Steam The double-flash steam power station is an improvement on the single-flash design as it can produce 15–25% more power output for the same geothermal fluid conditions. The station is more complex, more costly and requires more maintenance. However, the extra power output

Geothermal Power Conversion Technology. Figure 43
Wellhead valve, control valve (*left*), and vertical separators (*right*) (Courtesy of ORMAT)

often justifies the installation of such stations. According to DiPippo [33], 14% of all geothermal stations are double-flash units as of mid-2007.

Many aspects of a double-flash station are similar to a single-flash station. The fundamental new feature is a second flash process imposed on the separated liquid leaving the primary separator to generate additional steam at a lower pressure than the primary steam.

A schematic diagram of a double-flash station is shown in Fig. 14 [35] and in Fig. 44. The design differs from the single-flash station in Fig. 42 in that the low pressure steam from an additional flasher F flows through a steam line to the turbine in addition to the high-pressure line from the separator.

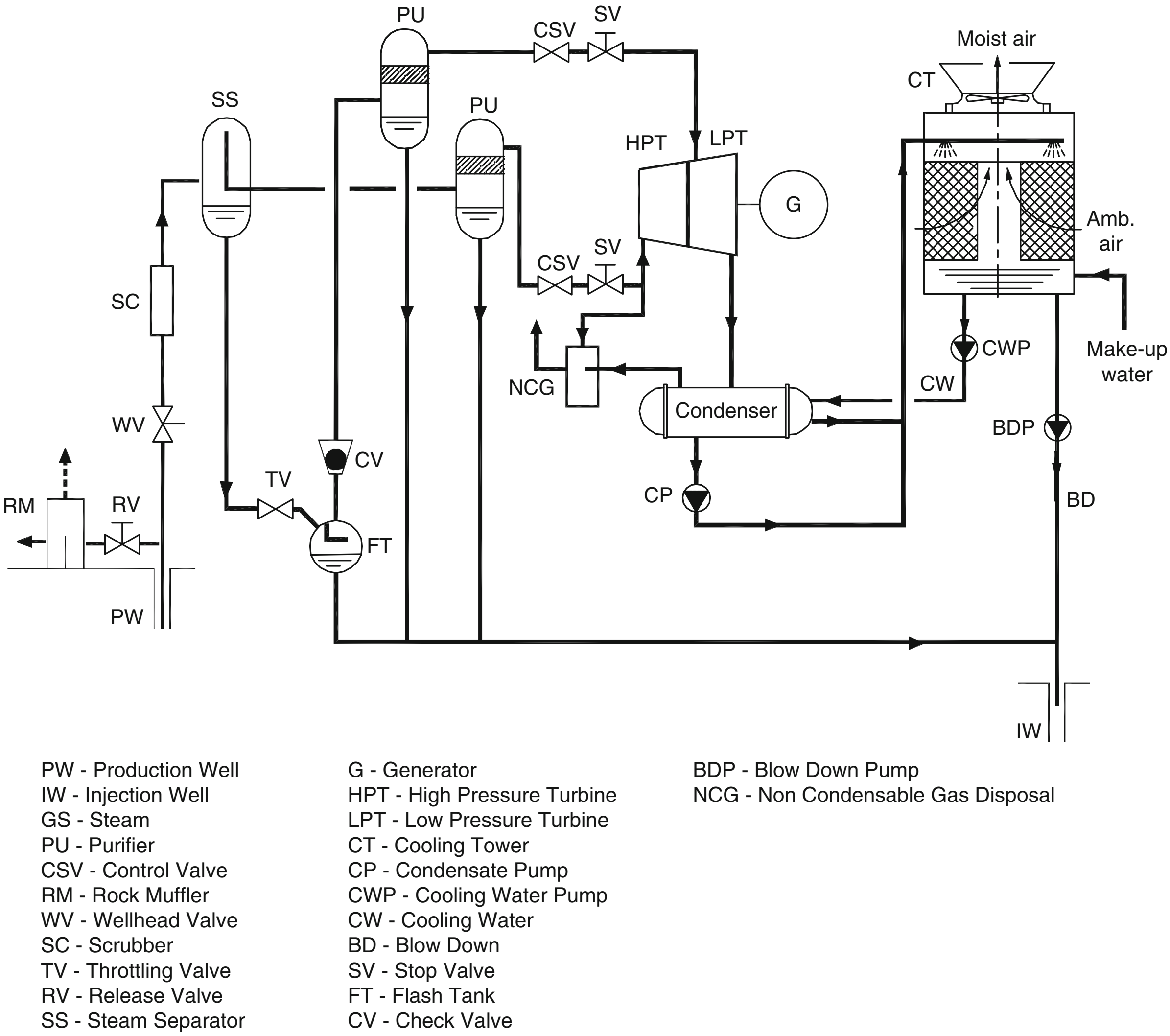
The turbine must be a dual-admission, single-flow machine to accommodate the high- and low-pressure steam supplies. The low-pressure steam is admitted to the steam path at an appropriate stage to smoothly integrate with the partially expanded high-pressure steam. Other designs are possible e.g., two separate turbines could be used, one for the high-pressure steam and one for the low-pressure steam. In such cases, the turbines could exhaust to a common condenser or to two separate condensers operating at the same or different levels of vacuum. For larger power ratings (50 MW or higher), double-flow turbines are preferred to minimize the height of the last stage blades.

Separators and Purifiers

Particle Separators Particles separators/purifiers are installed on steam lines after the wellhead flow control valve to remove particulates carried by the steam flow. The design is based on filtration by circular flow. Restrictions that create differences in flow velocity help the filtering of the steam-carried particles. To maintain correct separator velocity, more than one separator is installed on a single steam line, see Fig. 45. The collected brine and particles are collected from the bottom exit of the separator.

Separators It is important to separate the two phases efficiently prior to admitting the steam to the turbine. Liquid in the steam can cause scaling and/or erosion of piping and turbine components. Although there are a few designs in use for cyclone separators, the industry has generally settled on the simple Weber-type separator, depicted in Fig. 43 right side and Fig. 46. Lazalde-Crabtree [54] published an approach to designing such vessels. The paper presented two variations. One for a primary 1-phase separator and the other for a moisture remover. Their recommended guidelines for separators and moisture removers are summarized in Table 7.

In cases where the separators are situated at a distance from the power building, the steam transmission pipelines are fitted with steam traps (ST) to capture and



Geothermal Power Conversion Technology. Figure 44
Simplified double-flash power station schematic [35]

remove moisture that may form from condensation within the pipes. Prior to being admitted to the turbine, the steam may be scrubbed to remove any fine moisture droplets that may have formed in the transmission pipelines and escaped the steam traps. The moisture remover that is also known as purifier (PU) is usually located directly outside the power building.

Cyclone separators receive incoming two-phase flow via a tangent entry. The incoming stream circulates tangentially at high speed, so that the liquid flows down the separator inner walls and exits to an accumulating tank. The steam (still rotating) remains in the cyclone separator loosing small droplets which exit through a tube on the lower side of the separator, while the steam exits through exterior pipes in the center of the separator. From the accumulator(s) the brine is collected and sent to the reinjection well.

Purifiers Purifiers are needed to protect the turbines blades and structure from corrosion and impingement by removal of residue water droplets. Droplets are either carried by the flowing steam after separation (separation is not 100%), or formed by unintentional condensation on the steam pipe walls. Lazalde and

Geothermal Power Conversion Technology. Figure 45
Particle separators/purifiers (Courtesy of ORMAT)

Geothermal Power Conversion Technology. Figure 46
Scheme and photo of steamboat hills two-phase vertical cyclone separators and accumulators (Courtesy of ORMAT)

Crabtree [54] recommend a cyclone design similar to the separator but with small water exit due to the smaller water flow load. The basic design parameters are presented in Table 7.

Steam Scrubbing Unit Another method of final steam treatment is scrubbing. To improve the scrubbing, wash water is injected into the pipeline. TDS concentration in the pipeline is reduced by mixing

Geothermal Power Conversion Technology. Table 7 Separator and moisture remover design guidelines [54]

Parameter	Separator	Moisture remover
Maximum steam velocity at the 2-phase inlet pipe	45 m/s	60 m/s
Recommended range of steam velocity at the 2-phase inlet pipe	25–40 m/s	35–50 m/s
Maximum upward annular steam velocity inside cyclone	4.5 m/s	6 m/s
Recommended range of upward annular steam velocity inside cyclone	2.5–4 m/s	1.2–4 m/s

the low TDS wash water with the high TDS brine drops. Refer Fig. 47.

Steam line scrubbing is effective in removing liquid from the steam while maintaining a low TDS concentration in the liquid drops entering the turbine as steam impurities. The water injection system is shown in Fig. 48.

Flash Tank/Flash Chamber Flash chambers are vertical (Fig. 49) or horizontal (Fig. 50) with brine exits at the bottom of the tank. In Brady Power station, vapors from the first flash pass to two separate steam turbines while the brine that goes to the second flash chamber is re-flashed with its flash steam passing to a third steam turbine. A set of silencers is installed behind the flashing chambers in the case of a trip for part or all of the system.

Flash chambers may be installed horizontally above the condenser and vacuum system. The horizontal chamber has a large volume allowing droplets to settle as a result of low steam velocity. This reduces pressure losses.

Condensers

Surface Condensers In the use of surface-type condenser shown in Figs. 51 and 52, the required flow rate of cooling water $\dot{m}_{cw}$ related to the steam flow rate $X_2\dot{m}_{st}$. This is expressed by the First Law of thermodynamics as:

$$\dot{m}_{cw} = X_2\dot{m}_{st}\left[\frac{h_5 - h_6}{\bar{c}\Delta T}\right] \tag{72}$$

where $\bar{c}$ is the assumed constant specific heat of the cooling water (4.2 kJ/kg.K), ΔT is the rise in cooling water temperature at the condenser inlet and outlet and X_2 is the steam dryness stage at the turbine exit.

Direct Contact Condensers For a direct-contact condenser (Fig. 53), the suitable equation is:

$$\dot{m}_{cw} = x_2\dot{m}_{total}\left[\frac{h_5 - h_6}{\bar{c}(T_6 - T_{cw})}\right] \tag{73}$$

The condenser is below the flash chamber, see Fig. 54. The steam returning from the steam turbine is condensed via direct contact with the cooling water. Because of the open cooling cycle, air and other gases are entrained in the water. The NCG system must remove this air and gas to maintain the designed condensing temperature/pressure.

Air-Cooled Condensers Air-cooled condensers came to solve the problem of water scarcity in many geothermal sites, as well as to answer the environmental ruling against cooling towers plumes, etc. Air-cooled condensers are rarely used with flash steam mainly as they suffer from internal silica buildup. Today they are used in binary cycles despite the fact that the condensing temperature is higher by 15°C with water cooled condensers, but in arid zones it is the only solution. Air-cooled condensers are very sensitive to ambient air (temperature), and it can be controlled to some extent by fan speed control, higher exit shroud and optional water spray into the incoming air at extreme air temperatures. HTRI [55] design and similar software is commonly used for air-cooled condensers design. See Fig. 55 scheme and photo of actual air condensers arrangement.

$$\dot{m}_{cair}(h_{airout} - h_{airin}) = \dot{m}_{wf}(h_2 - h_3) \tag{74}$$

where h_2 is organic fluid condition at the condenser inlet and h_3 is the condition of the condensed liquid.

Assuming constant Cp for air in the relevant temperature range and neglecting humidity influence:

$$\dot{m}_{cair}Cp_{air}(T_{airout} - T_{airin}) = \dot{m}_{wf}(h_2 - h_3) \tag{75}$$

or

$$\dot{m}_{cair} = \dot{m}_{wf}\frac{(h_2 - h_3)}{Cp_{air}(T_{airout} - T_{airin})} \tag{76}$$

Geothermal Power Conversion Technology. Figure 47
Amatatilan steam scrubber, horizontal mixer, and vertical purifier (Courtesy of ORMAT)

Cooling Tower The cooling water used for heat rejection in the condenser of steam or binary stations is continuously re-cooled in the cooling tower. Cooling is achieved by evaporation of part of the circulated water into the ambient air. In large cooling towers, cooling be done by natural draft structure while in medium power systems (in geothermal stations), towers usually are equipped with mechanical draft fans.

The usual temperature difference in mechanical draft towers is about 10°C between the inlet and outlet of the moving air. Cooling water can reach about 25°C depending on the ambient air temperature and humidity. Cooling towers need makeup water to compensate for the evaporation and drift losses and to maintain water quality. The makeup is about 3% of the circulated water depending on ambient air characteristics. In geothermal flash power stations, there is sufficient water quantity collected from the flash steam condensate. In such stations, the condenser is usually of direct contact design which is simpler to design and is more cost effective in production than surface condensers used in binary stations (Fig. 56).

The internal process involves the exchange of both heat and mass between air and water. The following First Law equation describes the overall tower operation, excluding the fan while assuming steady

flow and overall adiabatic conditions for a tower with direct contact condenser:

$$\dot{m}_1 h_1 - \dot{m}_2 h_2 = \dot{m}_{\mathrm{Aout}} h_{\mathrm{Aout}} - \dot{m}_{\mathrm{Ain}} h_{\mathrm{Ain}} + \dot{m}_{BD} h_{BD} \quad (77)$$

Geothermal Power Conversion Technology. Figure 48
Mokai 2 – Brine scrubbing on steam line (Courtesy of ORMAT)

$$\dot{m}_1 + \dot{m}_{\mathrm{WAin}} = \dot{m}_2 + \dot{m}_{BD} + \dot{m}_{\mathrm{WAout}} \quad \text{(Conservation of water)} \quad (78)$$

$$\dot{m}_{\mathrm{Aout}} = \dot{m}_{\mathrm{Ain}} \quad \text{(Conservation of dry air)} \quad (79)$$

where the terms $\dot{m}_{\mathrm{wa}}$ and $\dot{m}_{\mathrm{wd}}$ represent water content of the incoming and leaving air streams, respectively. These contents can be determined from the specific humidity, ω, of the air streams:

$$\dot{m}_{\mathrm{WAin}} = \omega_{\mathrm{Ain}} \dot{m}_{\mathrm{Ain}} \quad (80)$$

and

$$\dot{m}_{\mathrm{WAout}} = \omega_{\mathrm{Aout}} \dot{m}_{\mathrm{Aout}} \quad (81)$$

These governing equations are used with the properties of steam, water and moist air, either in tabular, graphic (psychometric chart), electronic form to determine the various flow rates needed for given design conditions.

Cooling towers are characterized by two parameters:

- Range
- Approach

The range is the change in water temperature as it flows through the tower, namely, $T_1 - T_2$.

Geothermal Power Conversion Technology. Figure 49
Brady Double-Flash chambers with back silencers (Courtesy of ORMAT)

Geothermal Power Conversion Technology. Figure 50
GEM horizontal flash chamber (Courtesy of ORMAT)

The approach is the difference between the water outlet temperature and the wet-bulb temperature of the incoming air, namely, $T_2 - T_{\mathrm{wb.Ain}}$. Since the ideal outlet water temperature is the wet-bulb temperature of the incoming air, the approach is a measure of how closely the tower approaches ideal performance, i.e., zero approach or $T_2 = T_{\mathrm{wb.Ain}}$ (Fig. 57).

Pumps

Geothermal Fluid Pumps

Production Pump Production pumps are of multistage vertical design. The pump fits the bore diameter of the well casing and has a screen filter before its inlet opening. The motor sits directly on the wellhead, on top of the pump exit pipe. See Fig. 58. Pump pressure should be high enough to overcome all system piping friction while still maintaining pressure above possible precipitation of carbonates as mentioned in section on "Geothermal Resources."

Injection Pump The injection pumps are of horizontal or vertical multistage design to overcome injection well resistance. See Fig. 59 for typical arrangement. The structure must allow quick dismantling for maintenance work.

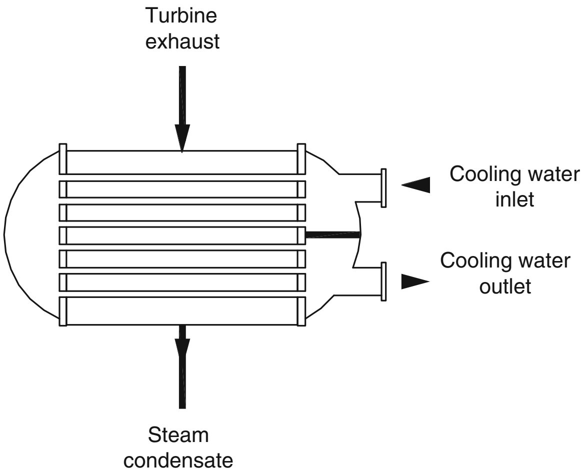
Condensate Pumps Condensate pumps overcome the subatmospheric pressure at the pump inlet and then lift condensate to the top of the cooling tower, overcoming distribution system and nozzles resistance. Typical pump is in Fig. 60.

Binary Station Motive Fluid Pump Motive fluid pump is situated below the condenser structure. To eliminate possible inlet vacuum buildup it is usually a vertical with barometric height above its inlet. Typical binary cycle circulation pump is in Fig. 61.

Gathering System

Dry-Steam Gathering The connection between the wells and the power building for a dry-steam power station is relatively simple. At the well, there are the usual valves and a steam purifier. See example in Fig. 62. The purifier is usually an in-line, axial centrifugal separator designed to remove all carried particles from the steam before it enters the piping system. Steam pipes are insulated and include high expansion loops. See example in Fig. 64. Steam traps are sited along the pipes to remove condensate.

At the wellhead, or immediately before the steam approaches the power building, there is an emergency pressure relief valve. This allows for the temporary release of steam in the event of a turbine trip. Before being released to the atmosphere, the steam generally passes through a silencer (Figs. 49 and 63). It has been found preferable to maintain the wells in a steady open mode rather than cycling the wells through open and closed positions. At the power building there is a steam header, a final moisture remover (typically a vertical cyclone separator or a baffled demister), and a venturi meter for accurate steam flow rate measurement.



Geothermal Power Conversion Technology. Figure 51
Surface condenser

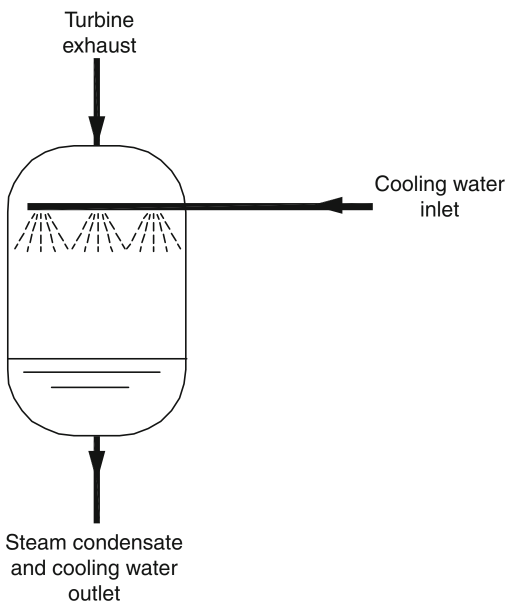
Water and Brine Piping High-pressure reinjection requirements might require pumps to maintain sufficient injection pressure.

Pressure drop through the pipes due to friction and local losses can be calculated using standard handbooks such as McKetta or similar [56]. The information required includes fluid mass flow rate, fluid density,

Geothermal Power Conversion Technology. Figure 52
Surface condenser end connections, NCG removal system, and cooling tower (Courtesy of ORMAT)

fluid dynamic and kinematic viscosity, pipe data such as pipe diameter, friction factor and length.

If there is a change in pipe elevation, the gravity contribution must be included.



Geothermal Power Conversion Technology. Figure 53
Direct contact condenser

Pressure loss in a two-phase, steam-liquid pipeline is more complex and less reliable for analytical prediction [57, 58]. Correlations may be used to establish the pressure drop. Field tests are conducted to experimentally determine the exact ΔP. The situation is complex as the two-phase flow in any of several different patterns depends on the pipe orientation and relative amounts of the phases present. See also references [58, 59] for suggested calculation depending on type of flow

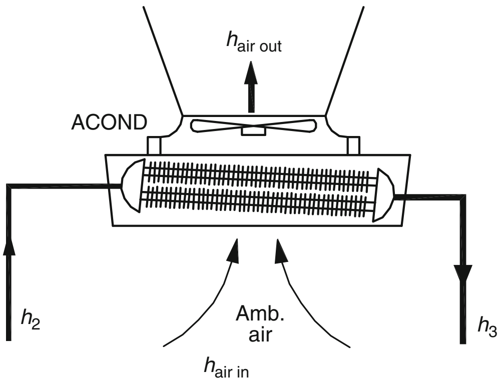
Steam Piping There are three types of fluids flowing in the geothermal field piping system:

- Steam
- Water/brine
- Two phase (mixture of steam and water)

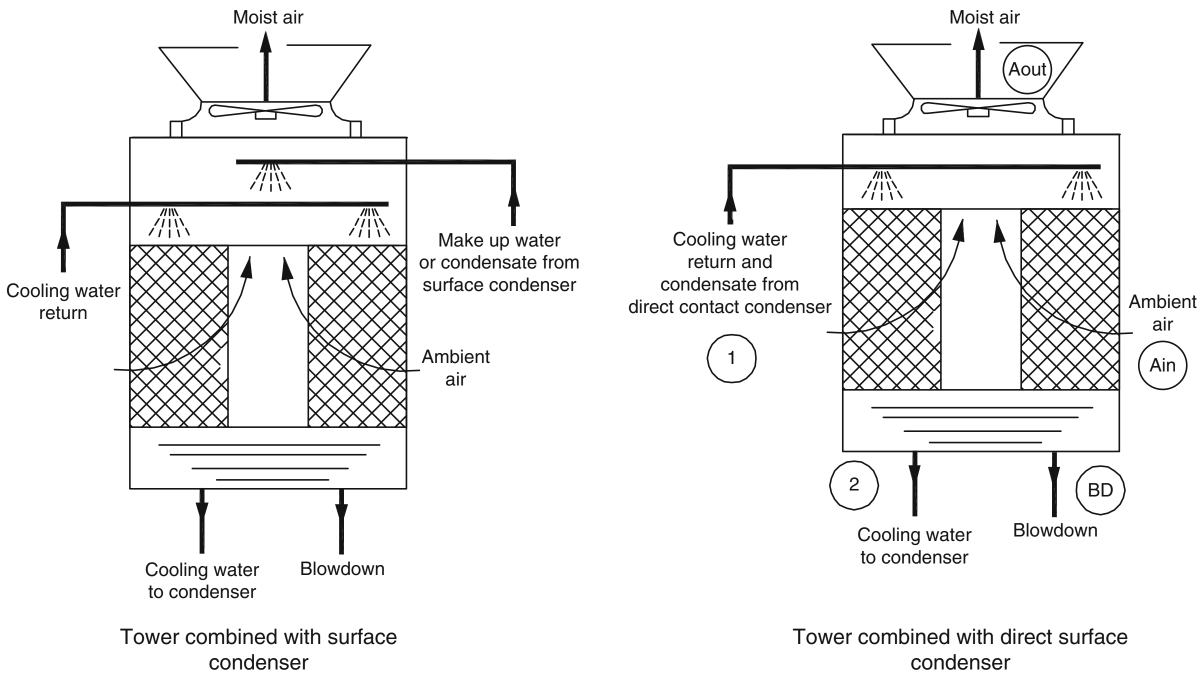
One of the main gathering system design concerns is the pressure loss in the steam lines from the wellhead to the power building. The steam pressure drop is a function of the diameter, length, configuration of the steam piping and the density and mass flow rate of the steam. See also Handbooks for fluid systems design such as ref. [56] or similar.

Note that the calculated pressure drop might be higher than the actual values at higher velocities.

Geothermal Power Conversion Technology. Figure 54
GEM direct contact condenser, hot-well pumps, and vacuum system (Courtesy of ORMAT)



Geothermal Power Conversion Technology. Figure 55
Air-cooled condenser view of the PGV Geothermal combined cycle power station (Courtesy of ORMAT)



Geothermal Power Conversion Technology. Figure 56
Induced draft cooling towers showing related mass flows

The central variable is the pipe diameter as pressure drop is inversely proportional to the pipe diameter in the fifth power.

By installing larger diameter pipes pressure loss can be considerably reduced. The extra cost of the larger pipes may be a negative economic factor. A thermodynamic-economic optimization study will determine optimum pipe size.

Single-Flash Gathering System Design Considerations and Piping Layouts When a geothermal field produces a mixture of steam and water, the method used

Geothermal Power Conversion Technology. Figure 57
Cooling towers of GEM single-flash power station in East Mesa, California (Courtesy of ORMAT)

Geothermal Power Conversion Technology. Figure 58
North Brawly production pump and separator with MCC (Courtesy of ORMAT)

for energy conversion depends on the potential energy available in each of the streams. The curves of maximum available energy for steam and water given in Fig. 8 can be used for the initial analysis. If the separated water stream is not sufficient for power generation, it will be reinjected, while the separated steam is utilized in a single-flash station for conversion to electricity. Each power station comprises a number of production and reinjection wells to assure continuous flow even during maintenance

Geothermal Power Conversion Technology. Figure 59 Injection pumps arrangement (Courtesy of ORMAT)

Geothermal Power Conversion Technology. Figure 60 Condensate pump (Courtesy of ORMAT)

work on any of the wells. A piping system is required between the wells and the installed steam/water separators (usually adjacent to the wells and the power building). There is also a brine piping system leading from the separators and power building to the reinjection wells.

A typical field is usually a few kilometers long with the production wells on one side, injection wells on the other side and with the power building positioned so as to minimize steam side pressure losses.

Double-Flash Gathering System Design Considerations In most cases, the second flashing process is performed near to the first steam separator.

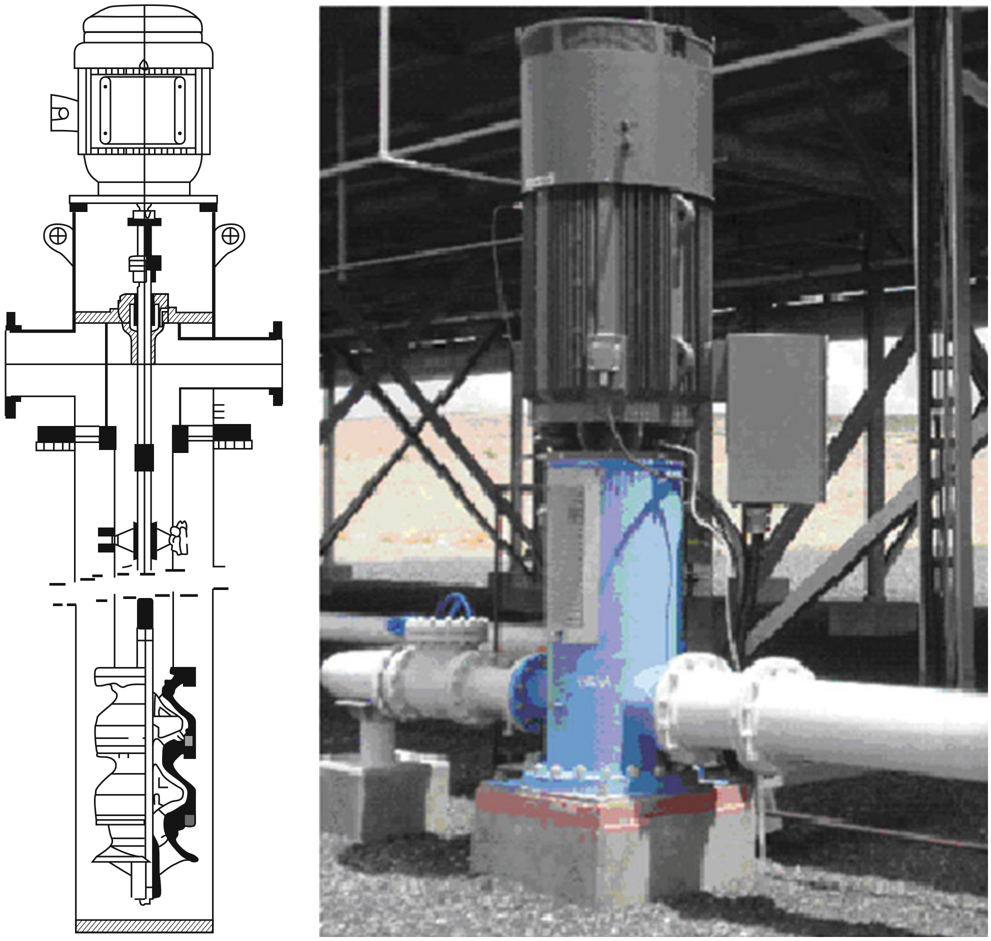
The list of possible arrangements is large and therefore the best choice will be determined by thermodynamic and economic analysis taking site-specific conditions including:

- Temperature, pressure, and chemical nature of the geothermal fluid
- Location of production and injection wells relative to the power building
- Topography of the site
- Method of fluid disposal, including any required scale-control techniques

For such analysis the pressure drop calculations for the various piping arrangements can use the formulas in "Water and Brine Piping" and "Single-flash Gathering System Design Considerations and Piping Layouts."

Two-Phase Flow The two-phase pipelines can be designed as elements of a geothermal gathering system. Take the correct pressure drop into account as it can be larger than that in single phase steam lines. The presence of unsteady flow patterns such as slug flow can cause excessive vibrations and should be avoided by proper pipe diameter selections. So-called flow pattern "maps" [57] can help the designer with the correct regimes.

Another important aspect concerns the flow of liquid removed from the cyclone separators. The fluid is in a saturated state and any pressure loss can cause it to flash into vapor. This will create a vapor barrier and inhibit the fluid flow down the well. In such cases it may be necessary to bleed the vapor from the wellhead or to install a booster pump upstream of the vapor breakout point. Also, any drop in temperature of the liquid may change the chemical equilibrium and cause precipitation as described in section on "Geothermal Resources."



Geothermal Power Conversion Technology. Figure 61
Binary power station – motive fluid circulation pump (Courtesy of ORMAT)

Choosing the Energy Conversion Systems

Introduction

Four basic types of geothermal energy conversion systems were covered in the section on "Thermodynamic Analysis of the Energy Conversion Process." There are geothermal resources demanding more sophisticated energy conversion systems than the basics considered until now. Furthermore, energy conversion systems have evolved to fit the needs of specific developing fields by integrating different types of power station into a complex facility described later.

Of the over 10,715 MW of geothermal stations in operation worldwide, most are steam stations operating on dry steam or steam produced by single or double-flash. About 1,000 MW use ORC or steam/ORC combined cycles [60, 61]. Table 8 compares various resources fluids and their temperatures that indicate site potential and recommended configuration.

Operational experience has confirmed the advantages of the ORC stations, not only for the low enthalpy water-dominated resources, but also at high enthalpy with aggressive brine or brine with high noncondensable gas content. The higher installation cost of these systems is often justified by environmental and long-term resource management considerations [62, 63]. The air-cooled ORC stations are particularly well adapted to the engineered geothermal systems (EGS).

Geothermal Power Conversion Technology. Figure 62
Production wellhead valve and control valves in PGV station, Hawaii (Courtesy of ORMAT)

Geothermal Power Conversion Technology. Figure 63
Rock Muffler in the station at Brady, Nevada (Courtesy of ORMAT)

Geothermal Power Conversion Technology. Figure 64
Brine line with expansion loop (Courtesy of ORMAT)

Geothermal Power Conversion Technology. Table 8 Comparison of basic geothermal energy conversion systems

Resource	Temperature	NCG	Dissolved slides	Configuration
Water	High or medium	Low	Low	Condensing steam (double-flash) *or* ORC
		High	Low	ORC
		Low	High	ORC
	Low	Any	Any	ORC
Water Dominated	High or Medium	Low	Low	Condensing steam double-flash *or* single-flash + ORC
		High	Low	ORC
		Low	High	ORC
	Low	Any	Any	Two-phase ORC
Steam Dominated	High or Medium	Low	Low	Condensing steam (single or double-flash) *or* condensing steam (single-flash) + ORC
		High	Low	Integrated Geothermal Combined Cycle
		Low	High	or Two-phase ORC
	Low	Any	Any	Two-phase ORC
Dry Steam	High or low	Low	Low	Condensing Steam
		High	Low	Geothermal Combined Cycle
		Low	High	Geothermal Combined Cycle
	Very High	Low	Low	Triple Flash Condensing
		High	Low	Geothermal Combined Cycle
		Low	High	Geothermal Combined Cycle

Optimization of the Design of the Power Cycle

The optimization of the whole geothermal power station system is accomplished by matching the working cycle and fluid properties to the resource characteristics,when considering not only resulting efficiency and cost, but also the impact on environment, long-term pressure support, requirements for makeup wells and O&M costs.

Resource Considerations Sustainability is defined as the ability to economically maintain the installed capacity over the life of a station [64]. With geothermal power stations, this is controlled by two factors, heat recharge and water recharge.

Sustainable heat flow to the station, beyond the natural heat recharge, is supported by accessing the stored heat through drilling additional wells over the life of the project.

The decline of production in the Larderello, The Geysers, and Wairakei fields has focused attention on the necessity for long-term pressure support by injecting as much of the geothermal fluid as possible back into the aquifer.

In brines rich in carbonates, flashing, as accomplished in conventional steam power stations leads to scaling of injection wells, reducing their life span.

Use of secondary loops and of downhole and booster pumps, as in air-cooled ORC power stations enhance sustainability by assuring complete water recharge while reducing both the fouling of heat exchangers and the scaling of injection wells.

Heat Cycle Considerations When the source is liquid phase only (sensible heat) the-ideal cycle would have a varying source temperature of a succession of infinitesimal Carnot cycles. In a subcritical Rankine cycle the constant temperature of the evaporation leads to a loss of energy, but because of the lower vaporization latent heat this drawback is lower than in a steam cycle.

The objective of attaining to the ideal cycle has been aimed at in proposing the super-critical Organic Rankine cycle, the total-flow regenerative cycle, the cascaded Organic Rankine cycle and the Kalina cycle. When dry steam is available, the most effective way is to use the conventional condensing steam cycle.

When the source is a mixture of steam and brine and/or has a high content of noncondensable gases, the most effective utilization of the resource is achieved through a combined geothermal cycle by firstly expanding the steam in a back-pressure steam turbine. The heat of condensation together with the heat of separated brine is then used to drive a bottoming ORC.

To compare the efficiency of the different systems it is necessary to consider the net output of parasites, such as cycle pumps, production pumps, injection pumps, cooling systems and noncondensable gas extraction power consumption [63].

Work Ratio, Parasitic Losses, and Impact on Total Cost These considerations arise in every design of new power station. These are many options to consider, a few examples follow below. While the technical issues are general, the economic decision is site specific and depends on the type of financing, interest rate, contracted price of electricity, etc.:

- Condensing temperature

  The heat source temperature is a given factor that cannot be modified. However, the decision on the condensing temperature is negotiable and is a result of technical and economical considerations. Additional heat exchange area to a surface condenser or air-cooled condenser improves the work ratio, but adds cost of hardware. The question is whether the cost of additional kW installed or additional kWh produced per year can be justified economically.
- Single-flash or double-flash steam cycle

  Although the technical advantage of double flashing is understood and is considered to add about 20–30% to the output per well, actual site evaluation is still required. The factors to be considered are source size, heat source temperature, ratio between water and steam, etc. Additional pieces of equipment and different turbines may be required. All this affects the relative cost against the energy gain.
- Subcritical or supercritical operation of binary cycle

  Subcritical operation system is simpler to construct and operate but has limitations in heat transfer between the brine and working fluid. Supercritical cycles improve the heat transfer but require high-pressure operation increasing the pump power.

- Cascading vs. supercritical cycle

  A cascading binary cycle system is a simple solution to heat transfer improvement, while avoiding supercritical cycle limitations. The gain in power output is considered against cost of equipment. Even though multistaging is theoretically the best for gain in efficiency, the practical cost comparison dictates dual- or triple-stage design. Another consideration in cascading systems is the reduced brine temperature that can cause precipitation in the heat exchangers. This is partially compensated for by keeping the brine side under higher pressure (also has some cost impact).

Cooling System Consideration In steam Rankine cycle systems the use of condensate as makeup water is the most cost effective approach.

In areas with no natural water recharge of the geothermal reservoir and no surface water available, air cooling has been used by implementing air-cooled ORC for low-temperature resources or geothermal combined cycle for high-temperature resources. The value of the air-cooled ORC is important in case of EGS which is highly dependent on water recovery ratio.

Environmental Considerations Use of air-cooled ORC reduces the impact on environment by reinjection of:

- Noncondensable gases (mainly H_2S released by the steam)
- Discharged fluids such as the separated brine (carrying heavy metals) and blow-down from the cooling tower (chemicals) and drift from cooling towers.

Commercial Power Stations

Steam Power Stations

Dry-Steam Power Station

General Dry-steam stations were the first type of geothermal power station to achieve commercial status with their history going back 100 years [66].

Dry-steam stations tend to be simpler and less expensive than flash-steam stations in that there is no geothermal brine to contend with. As can be seen, this is a positive issue when it comes to maintaining reservoir performance.

Large dry-steam reservoirs have been discovered only in two areas of the world; Larderello and The Geysers. There are limited dry-steam areas in Japan (Matsukawa), Indonesia (Kamojang), New Zealand (Poihipi Road section of Wairakei) and the USA (The Geysers, California). White [27] estimated that only about 5% of all hydrothermal systems with temperatures greater than 200°C are of the dry-steam type.

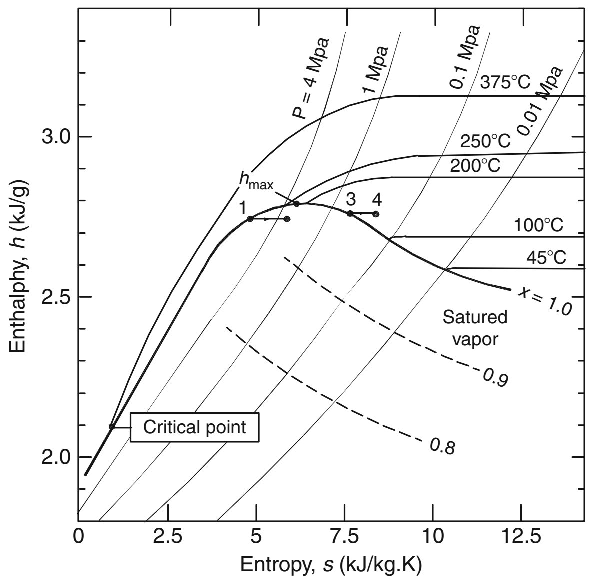
The general characteristic of a dry-steam reservoir is that it comprises porous rocks featuring fissures or fractures, either occluded or interconnected, that are filled with steam. Whereas the steam also contains gases such as carbon dioxide, hydrogen sulfide, methane, and others in trace amounts, there is little or no liquid present.

The dry steam extracted from the mentioned resources is either saturated or slightly superheated at temperatures near 235°C and pressure near the maximum saturation in Molier curve (30.7 bars) as in Fig. 65. Isenthalpic pressure loss in the upper layers (1–2, or 3–4, respectively) explains the superheated condition at the turbine inlet, but does not explain how the steam sometimes remains saturated at the wellhead.

There are over 60 flash or dry-steam commercial stations in operation, each with average power of 40 MW.

Energy Conversion System Once the steam reaches the power building, a dry-steam station is essentially the same as a regular low-temperature boiler steam station. The turbines are single-pressure units with impulse-reaction blading, either single-flow for smaller units or double-flow for large units above 50 MW. The condensers can be either direct-contact (barometric or low-level) or surface-type (shell-and-tube). For small units it is often advantageous to arrange the turbine and condenser side-by-side for maintenance reasons.

A typical dry-steam power station scheme is shown in Fig. 41 and the corresponding steam process is in Fig. 13 (repeated here in Figs. 66 and 67). Since the wells produce saturated steam (or slightly superheated steam), the starting point (state 1) is located on the saturated vapor curve. The turbine expansion process 1–2 generates somewhat less power output than the



Geothermal Power Conversion Technology. Figure 65
Mollier chart for water (maximum enthalpy at T∼235°C and P∼3.07 MP)

ideal, isentropic process 1–2s. Heat is discarded to the surroundings in the condenser via the cooling water in process 2–3.

The turbines used in geothermal applications must be made of corrosion-resistant materials owing to the presence of gases such as hydrogen sulfide that can damage ordinary steel.

Single-Flash Power Stations Since single-flash stations have a significant amount of waste liquid from their separators that is still fairly hot (typically 150–170°C), this can be used to generate more power instead of being directly injected. Combined single- and double-flash stations have been built at several fields around the world.

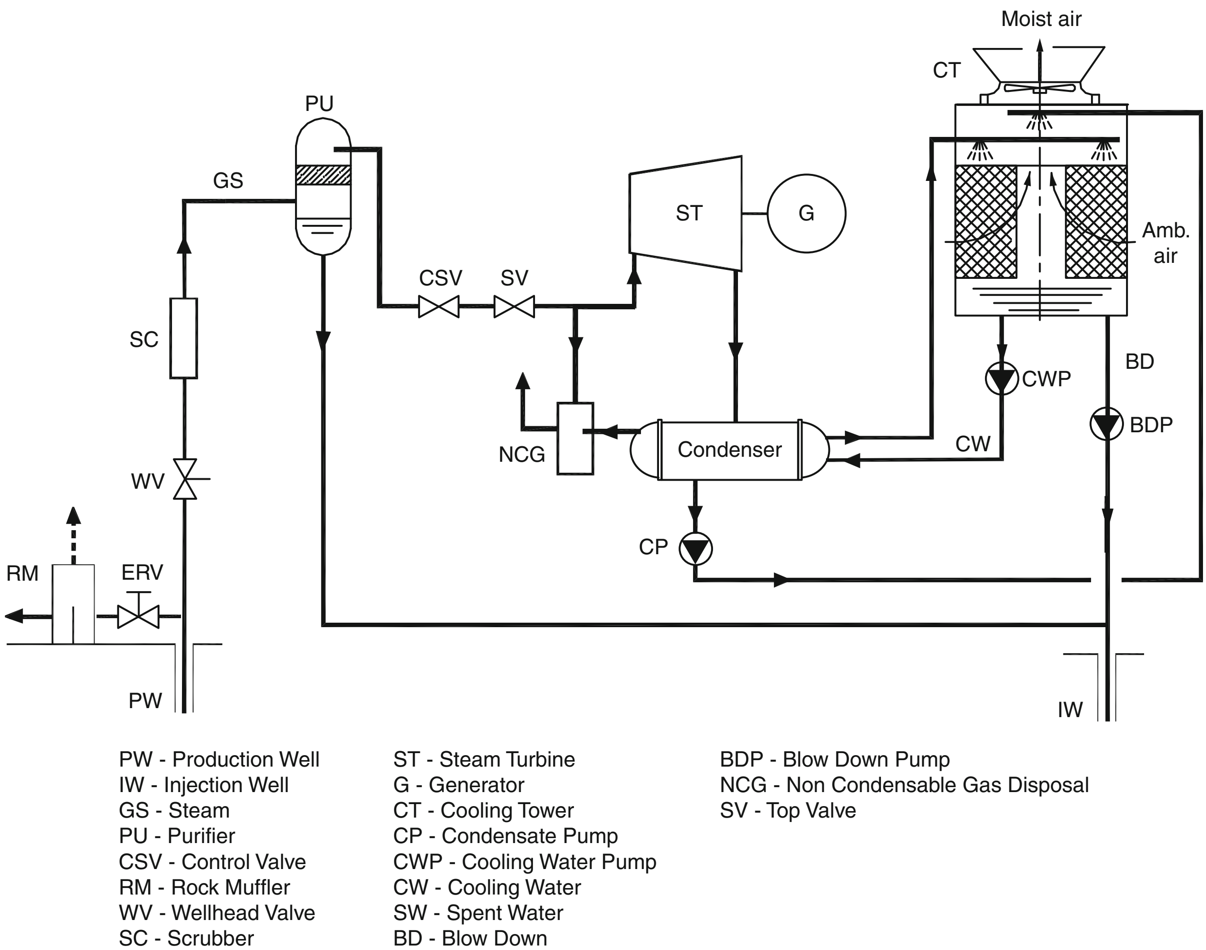
Double- and Triple-Flash Power Stations Double-flash cycles as in Fig. 44 are justified due to the high temperature of the waste brine remaining from the first flash. For such cases the turbines are designed to handle dual-pressure steam. Also, to maintain symmetric axial force on the turbine bearings and shorter blade height they are designed as double-flow machines. See scheme in Fig. 68. In some cases the source temperature and flow-rate justifies triple flashing as in the case of NGA AWA PURA power station in New Zealand shown in Fig. 69. The general station scheme is given in Fig. 70 and the turbine steam flow is given in Fig. 71. The Fuji 120 MW turbine is given in Fig. 72. However, mass flow does not always justify the construction of the special two admittance turbine. This lead to combinations as integrated single and double-flash stations, combined single and double-flash units as will be described later.

Integrated Single and Double-Flash Stations Single-flash units have been built and have been operating for a period of time where the geothermal fluid reservoir temperature is about 220–240°C. The addition of one more flash using the separated brine allows for a lower pressure unit. The arrangement shown in Fig. 73 consists of two single-flash units, Units 1, Unit 2 and Unit 3, added at a later date appears to be simply another single-flash unit. The power station as a whole is an integrated single- and double-flash facility since the original geothermal fluid experiences two stages of flashing [35].

The advantage to this arrangement is that no new wells need to be drilled to supply the third unit. Unit 3 serves as a bottoming unit recovering some of the wasted potential from the still-hot brine. The thermodynamic process diagram is given in Fig. 74.

One possible thermodynamic drawback to this arrangement lies in the selection of the pressure (or equivalently, the temperature) for the second flash process 3–6 in Fig. 74. If the flash temperatures for the first two units (assumed identical) had been optimized, then the addition of the third unit requires not only new optimization but evaluation of possible use of the existing equipment.

Combined Single- and Double-Flash Stations When the resource temperature is equal to or greater than 240°C, it may be possible to augment the single-flash units with a true double-flash bottoming cycle, as in the schematic flow diagram Fig. 75, and in the process diagram Fig. 76. For this case, the waste brine from the first units is subjected to two flashes, resulting in two additional low-pressure steam flows to be utilized in a dual admission turbine. The arrangement can be named as “combined single- and double-flash station” [35].



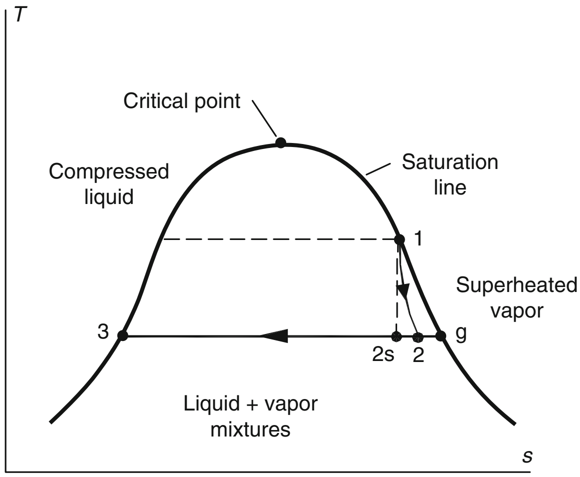
Geothermal Power Conversion Technology. Figure 66
Simplified scheme of a dry-steam power station

Although the thermodynamics of this arrangement are favorable, i.e., a higher resource utilization efficiency than for the original single-flash station, there may be problems with chemical scaling. This due to silica precipitation at low temperatures associated with the last flash as discussed in section on "Geothermal Resources." Therefore few flashes would not be a good choice unless there is no possibility of silica precipitation or if silica treatment is considered as part of the investment.

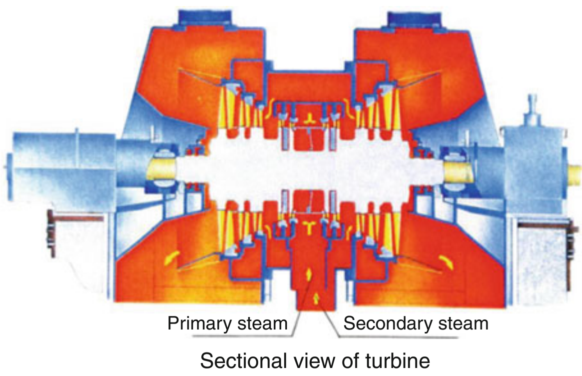
Power Stations Using Hyper Saline Brines In some geothermal sites, the underground soil formation is comprised of various materials that when dissolved into the hot water cause the water to become acidic and saline. This water can clog a production well or the downstream piping and heat exchangers in a few days, or render surface vessels useless by contamination.

One of the most notorious geothermal resources is located in the Imperial Valley of southern California, near the southeastern shore of the Salton Sea. The resource was recognized in the 1850s when explorers moving west came upon hot pools and mud volcanoes in an otherwise barren desert [67].

Drilling for power production began in the 1960s but the early wells were all plugged and abandoned. Some wells drilled in the 1970s are still in operation today, but the fluids that were produced resisted exploitation for power generation because of severe scaling



Geothermal Power Conversion Technology. Figure 67
Temperature-entropy diagram for dry-steam station (steam saturated at the turbine inlet)



Geothermal Power Conversion Technology. Figure 68
Scheme of double-flow dual-pressure turbine (Courtesy of Mitsubishi)

and corrosion problems. The temperatures were high (up to 360°C), and the total dissolved solids reached as much as 300,000 ppm, placing these fluids in the hyper saline category. The chemical analysis of the fluid produced from the Magmamax No. 1 well drilled in 1972 showed that chlorides, sodium, calcium, and potassium make up about two thirds of the 300,000 TDS in the brine [68].

An extensive research effort began in the 1970s funded by the US Department of Energy, the Electric Power Research Institute and several private companies. Through this effort, techniques were devised that later permitted these fluids to be used for the generation of electricity in a reliable and cost-effective manner [69]. Two approaches for dealing with these aggressive brines have been used with reasonable success, flash-crystallizer, reactor-clarifier (FCRC) and pH modification (pH-Mod) systems. The principles underlying these two methods are detailed below.

Flash-Crystallizer/Reactor-Clarifier (FCRC) Systems In the FCRC approach, clean steam is generated in a train of separators and flash vessels, similar to standard flash-steam power stations, but the separated brine is seeded with material inducing precipitation. A simplified schematic of an FCRC power station is shown in Fig. 77 [69]. The seed material is obtained from the highly concentrated brine waste stream. In this way, the unstable, supersaturated solids precipitate on the seed particles, rather than on the surfaces of the vessels and piping. The particulate matter eventually settles in a reactor-clarifier vessel. The slurry from the reactor-clarifier is thickened and a portion of it is recirculated as seed material. The clarified liquid is pumped to a secondary clarifier and then sent to reinjection wells.

The most recent power station to use this approach, Salton Sea Unit 5, has a triple-pressure turbine that receives the high-pressure steam separated at the wellhead separators and expands it through the first four stages of the turbine [70]. This eliminates the throttling loss from the pressure-letdown throttle valve TV shown in Fig. 77.

pH Modification (pH-Mod) Systems Section on "pH" discussed the option of pH control to protect against silica scaling. One approach is to modify the brine pH altering the kinetics of the precipitation process. The technique of acidifying the brine has been used in some Salton Sea stations as an alternative to the FCRC approach. Acids proposed for pH control are Hydrochloric acid HCl [71] and various sulfur-based acids [72]. By reducing the pH of the geothermal fluid the solubility of silica is increased, kinetics of the reaction are slowed and it is possible to avert precipitation, at least until the separated liquid has been processed to generate the flash steam needed for the turbine. A highly simplified flow diagram for a pH-Mod station is shown in Fig. 78 [73].

Geothermal Power Conversion Technology. Figure 69
Awa Pura Power station in New Zealand (Courtesy of Fuji Electric)

The addition of hydrochloric acid to the brine requires appropriate corrosion-resistant materials. However, pH-Mod stations are much simpler than FCRC stations in terms of the number of vessels needed and the operating procedures to be followed.

The processing of the discharge waste brine D is omitted from Fig. 78 but treatment may be needed. If the injection faces problems in the pipelines or the injection wells, then the brine pH must be raised. In addition, a reactor-clarifier can be used to remove the silica and assure that the waste brine can be safely injected. Work has been done on the economics of recovered minerals from the brine – which in itself is a by-product [74].

With these two methods for handling Salton Sea brines (FCRC and pH-Mod), it has been possible to construct ten power stations with a total capacity currently generating 327 MW net [75]. It is believed that a significant portion of the ultimate potential of the geothermal field lying offshore beneath the Salton Sea is far from being fully exploited. The technologies described in this section should allow this valuable resource to reach its full potential.

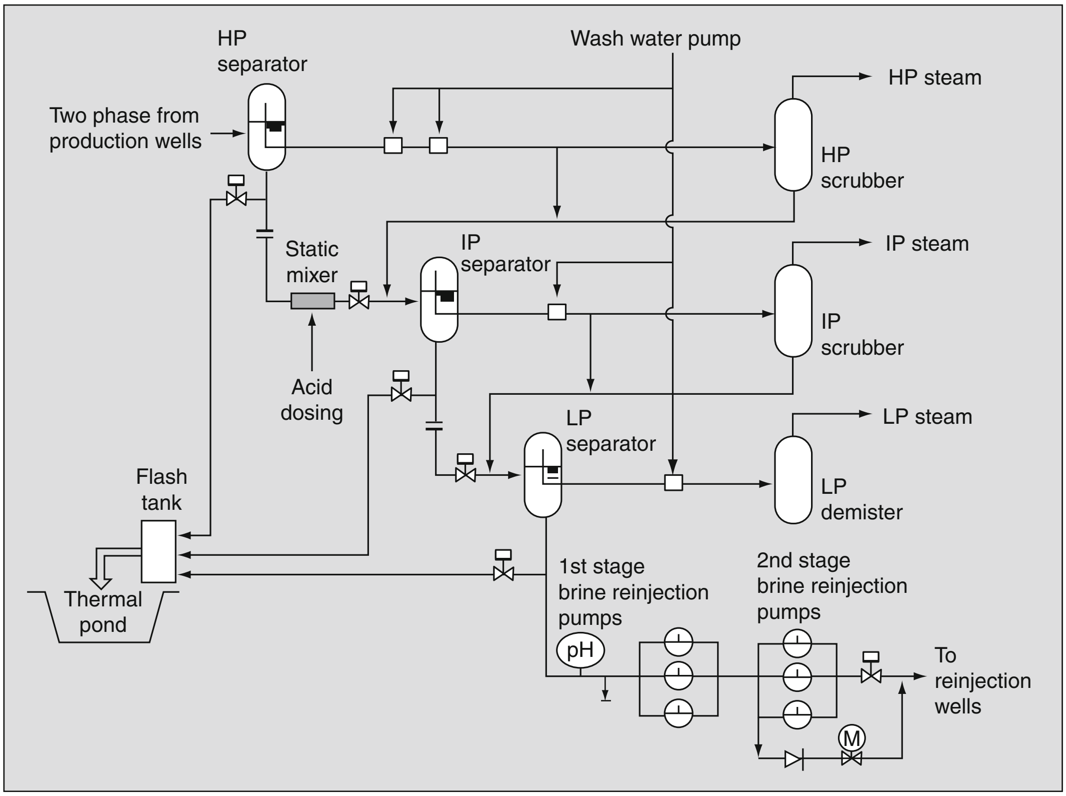
Organic Rankine Cycle Configurations for Geothermal Power Stations

Binary Power Stations

Single-Phase ORC In cases where the geothermal fluid temperature is 150°C or less, flash systems require intensive engineering work including large flashing vessels and brine treatment both in the production and reinjection pipes and wells. In addition, in most cases, at such temperatures a production pump is required to maintain continuous geofluid flow and pressure to prevent scaling.

Although the GEM station at East Mesa in the Imperial Valley of California in the USA [34] flashes the compressed liquid as in Fig. 79, it is simpler to pass the geothermal fluid as a compressed liquid through heat exchangers and dispose of it (in the liquid phase) into reinjection wells. By improving the heat transfer across the heat exchangers an economically viable design is obtained. A water-cooled, brine-driven binary cycle is in Fig. 80 [35] and an air-cooled system is given in Fig. 81 [61].

The production wells (PW) are fitted with deep well pumps (P) and are set below flash depth determined by



Geothermal Power Conversion Technology. Figure 70
Nga Awa Pura steam separation system overview (Courtesy of Fuji Electric)

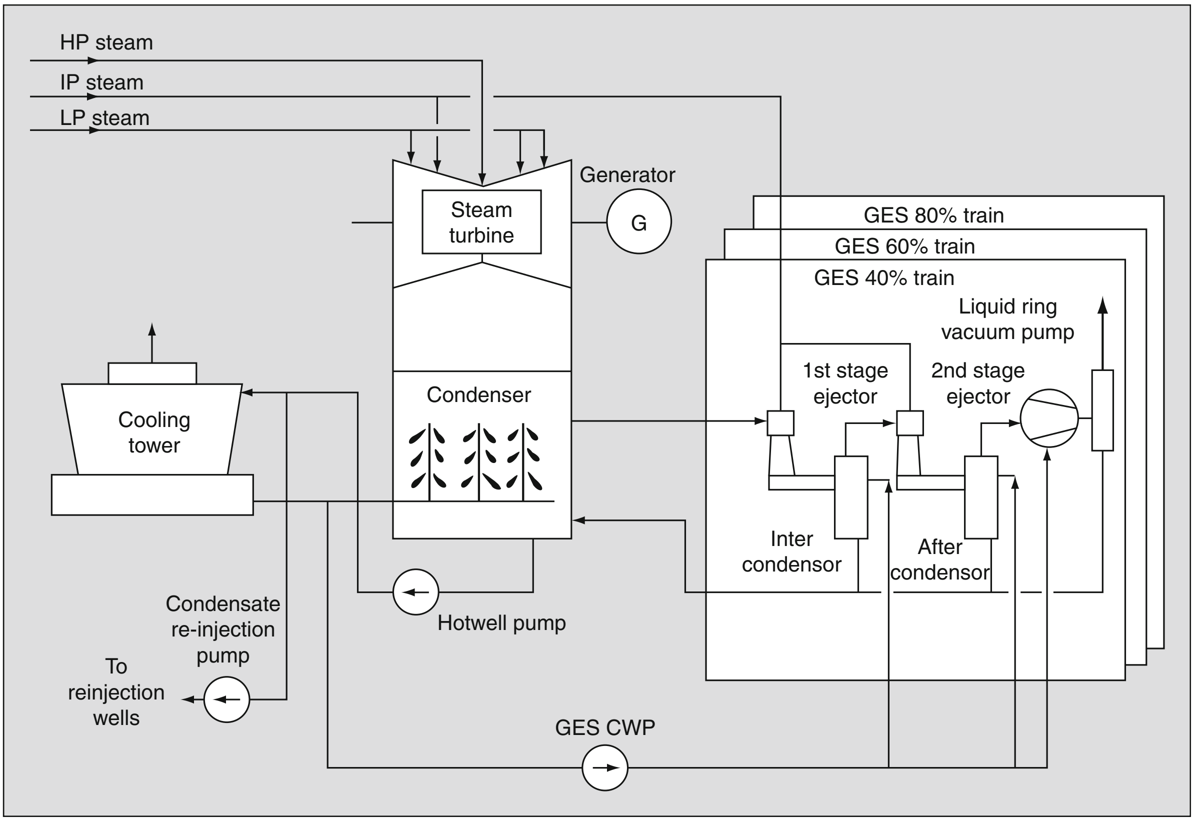
the reservoir properties and the desired flow rate. Sand filters SF are used in most cases to prevent scouring and erosion of the piping and heat exchanger tubes. Typically there are two steps in the process. First the working fluid flows through a preheater PH where it is brought to boiling point, then it flows to the evaporator E acquiring the supplemental heat of evaporation, emerging as a saturated vapor. The working fluid then expands in the turbine, recondenses in the condenser, and is pumped back to the preheater via a feed pump.

The geofluid flows to the evaporator, then the preheater and to the reinjection well. The geothermal fluid is always kept at a pressure above its flash point for the fluid temperature to prevent the breakout of steam and noncondensable gases that leads to calcite scaling in the piping. Furthermore, the fluid temperature is not allowed to drop to the point where silica scaling becomes an issue in the preheater, piping, and reinjection wells. Therefore chemical problems mentioned in section on "Geothermal Resources" are eliminated.

Temperature Cascading Organic Rankine Cycle To increase the power output of a binary power station, a cascading system can be used. In a simple cascading method there are two or more evaporators and preheaters, arranged consecutively in consequent structure. The geothermal fluid travels from one pair of units to the next. The station schematic given in Fig. 27 incorporates three levels of organic systems, each working at a different range of temperatures.

All preheaters begin from the same temperature but evaporation is performed at three different temperatures, therefore three turbines are required for such operation, ensuring the cooled brine is better utilized by the preheaters with part of the preheating in the evaporators. A T-Q diagram of the schematic arrangement of this system is given in Fig. 28.

A two-level cascading based on two turbine integrated over one generator was used in Ormat Heber brine station as given in Fig. 82. The brine enters level 1 evaporator then the level 2 evaporator. From this level



Geothermal Power Conversion Technology. Figure 71
Nga Awa Pura power generation facility overview (Courtesy of Fuji Electric)

the brine goes to the preheaters of both levels. The turbines of both levels are connected to single generator. The turbines of each level can be divided into HP and LP turbines, with each pair driving a single generator. Both condensers are water cooled sharing the same cooling water supply line. The station is shown in Fig. 83.

Recuperated Organic Rankine Cycle In most actual cases, the perfect match above is not feasible because of limitation of the brine and condensate mixture cooling temperature. In most of the cases the limiting factor is the silica scaling risk, which increases as the brine temperature drops. A method to partially overcome the cooling temperature limit is to add a recuperator which provides some of the preheating heat from the vapor exiting the turbine.

The recuperator is applicable when the organic fluid is of the "dry expansion" type, a fluid where the expansion in the turbine is done in the dry superheated zone and the expanded vapor contains heat that has to be extracted prior to the condensing stage (see [36, 77]). The recuperated Organic Rankine cycle is typically 10–15% more efficient than the simple Organic Rankine cycle described in the beginning of this chapter (Fig. 66 for comparison). This applies to the two-phase geothermal power station in Fig. 84 with its T-Q diagram in Fig. 85.

The recuperated two-phase process is used by Ormat in many geothermal projects around the world, i.e., 20 MW Zunil in Guatemala, 14 MW Ribeira Grande I and II in San Miguel in the Azores (Fig. 86), and 1.8 MW Oserian and 13 MW Olkaria III in Kenya.

Two-Phase Geothermal Power Station In the majority of worldwide geothermal fields, the geothermal fluid is separated in an aboveground separator into a separate stream of brine and steam. In a low to

Geothermal Power Conversion Technology. Figure 72
Nga Awa Pura view over turbine generator (Courtesy of Fuji Electric)

moderate enthalpy resource, the steam quality is 10–30% of the entering fluid quality if comparing enthalpy and separation pressure. The two streams can efficiently be utilized in a two-phase geothermal station as shown in Fig. 87. Separated steam (usually with some percentage of noncondensable gases or NCGs) is introduced in the evaporator to vaporize the organic fluid [81].

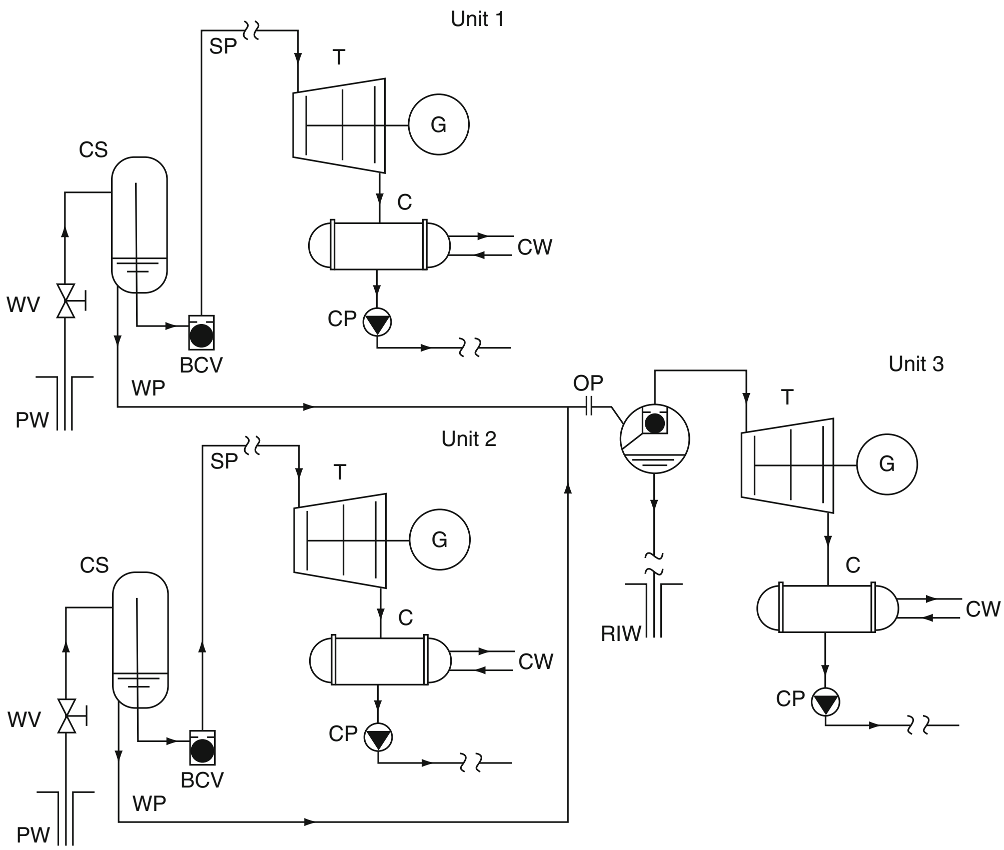
The geothermal condensate is mixed with the separated brine to provide the preheating medium of the organic fluid. In the ideal case, presented in the T-Q diagram (Fig. 88), the latent steam heat equals the heat of vaporization of the organic fluid and the sensible heat of the brine plus condensate equals the heat required to preheat the organic fluid. This "perfect" heat transfer match between the geothermal fluid and the working fluid represents maximum thermodynamic efficiency with minimum losses.

Higher Enthalpy Two-Phase Geothermal Power Station When the resource enthalpy is higher with an increase in proportion of steam in the total fluid, the "perfect match" between the heat source and the working fluid is not maintained. Some of the available heat or available energy is lost for power generation.

To utilize the two-phase heat source in a more efficient manner, a secondary organic loop is used, utilizing the extra steam available. The cycle shown Fig. 89 is feasible when vapor extraction is possible within the expansion phase of the organic cycle. The simplest way to perform the extraction is with two turbines in series. In this case, some vapor is extracted between the high-pressure and the low-pressure turbines and condensed at an intermediate pressure (and temperature).

The condensed vapor preheats the main organic fluid stream as it exits the recuperator. The extracted organic fluid forms a secondary cycle which generates an additional 5–8% electrical power. When there is extra steam compared to brine (higher enthalpy) the above cycle is effective and the cooling temperature of the brine plus condensate is limited.

Figure 90 is a flow temperature diagram of the higher enthalpy cases. Line A is the simple two-phase cycle preheating phase. The significant irreversibility is represented by the large space between the steam and brine lines and line A. Line B shows the preheating phase



Geothermal Power Conversion Technology. Figure 73
Integrated single- and double-flash power station [35]

in a recuperated two-phase cycle. Here irreversibility is reduced and the cycle efficiency is increased accordingly.

The third line, C, demonstrates the additional gain in efficiency by using the two-phase/extraction cycle. The line moves further to the right, thus decreasing the gap between the heating line and the working fluid line. Another indication of efficiency increase from cycle A to B and to C, is the increasing heat quantity for heating the working fluid, as presented by points QA, QB, and QC.

Hybrid Geothermal Cycles

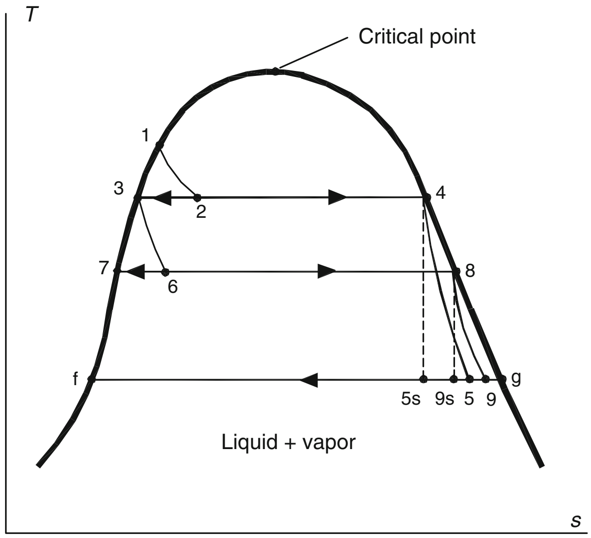
The various configurations of hybrid steam and organic Rankine cycles are:

ORC bottoming of flash power stations
Geothermal combined cycle
Integrated geothermal combined cycle
Use of a back pressure steam turbine

ORC Bottoming of Flash Power Stations An elegant alternative to the use of bottoming flash stations at existing single-flash stations is to add a bottoming Organic Rankine cycle. Combined flash-binary stations are in operation at several station sites around the world (see DiPippo [73], Appendix A). A different approach is to design a station, from scratch, as an integrated flash-binary station, thereby taking advantage of the best features of both units.

For this case, assume that a single-flash station has been running for some time (usually a few years), and the reservoir has shown itself capable of sustaining operations for many more years. The power output can be raised by adding a binary unit between the separators and the reinjection wells. A simplified schematic of such an arrangement is given in Fig. 91.

Such modification to the initial field design have been made in Momotombo, Nicaragua. The initial steam-only station comprised of two 35 MW Franco

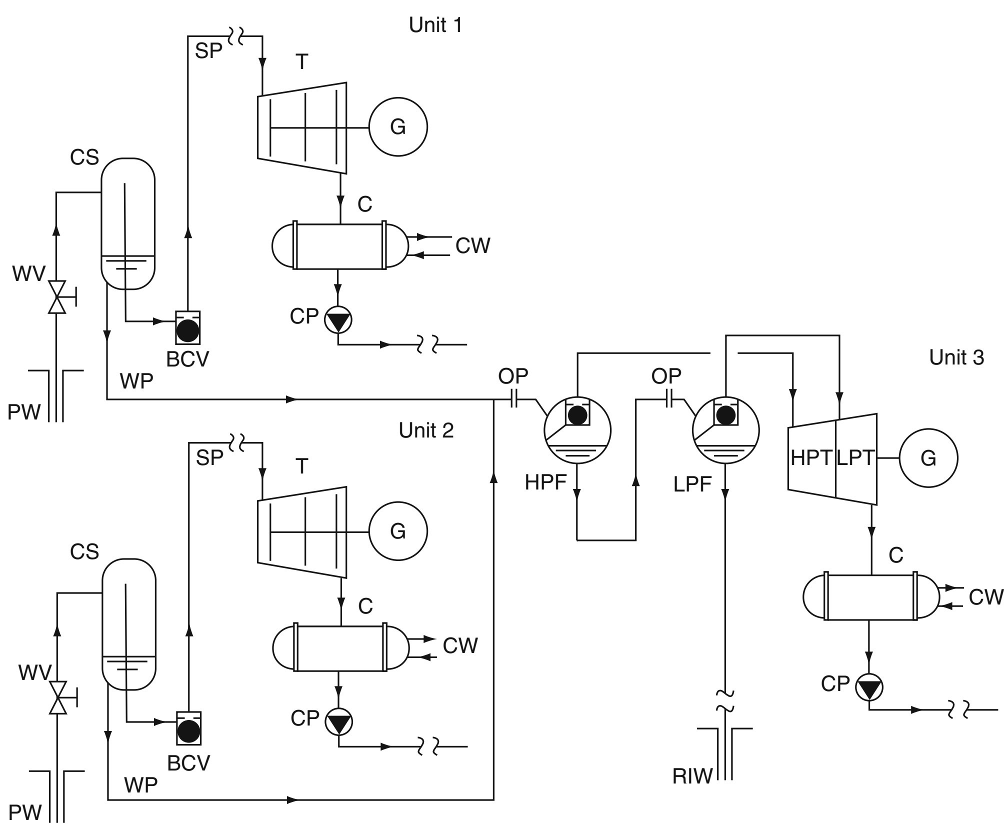


Geothermal Power Conversion Technology. Figure 74 T-S diagram for the integrated single- and double-flash power station in Fig. 73

Tosi steam turbines was enhanced by Ormat 9 MW binary bottoming cycle combined with one of the steam turbines as in Figs. 92 and 93. The field suffered from reduced steam production, reduced temperatures, injection difficulties that required more and deeper wells to regain the original field power production allowing the use of the second steam turbine, and possible additional bottoming cycle.

Initially the single-flash station operated alone and waste liquid from the cyclone separators CS was sent directly to the injection wells IW. The Organic Rankine cycle is inserted as shown to tap into the reinjection pipeline where it extracts some heat thereby lowering the temperature of the waste brine prior to injection. The additional power generated by the Organic Rankine cycle is gained without any new production wells.

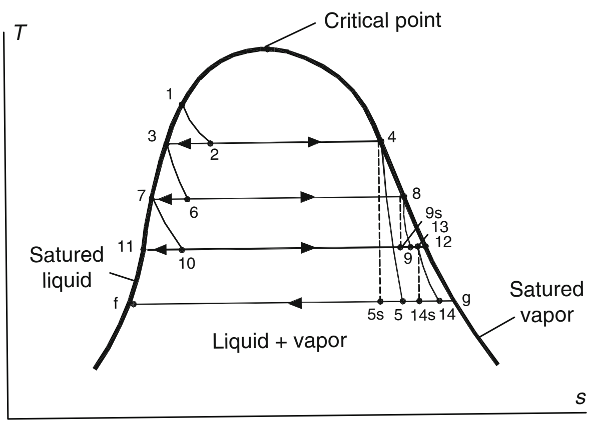
The thermodynamic process coordinates to facilitate comparison with the cycles in the previous sections. The power units are coupled thermodynamically



Geothermal Power Conversion Technology. Figure 75 Combined single-and double-flash station [35]

through the preheater FH and the evaporator E. Using the state points of Fig. 91, the First Law gives the relationship between the brine flow rate $\dot{m}_b$, from the wells (state 1) and that of the Organic Rankine cycle working fluid $\dot{m}_{wf}$:

$$\dot{m}_b(1 - x_2)c_b(T_3 - T_2) = \dot{m}_{wf}(h_a - h_c) \qquad (82)$$



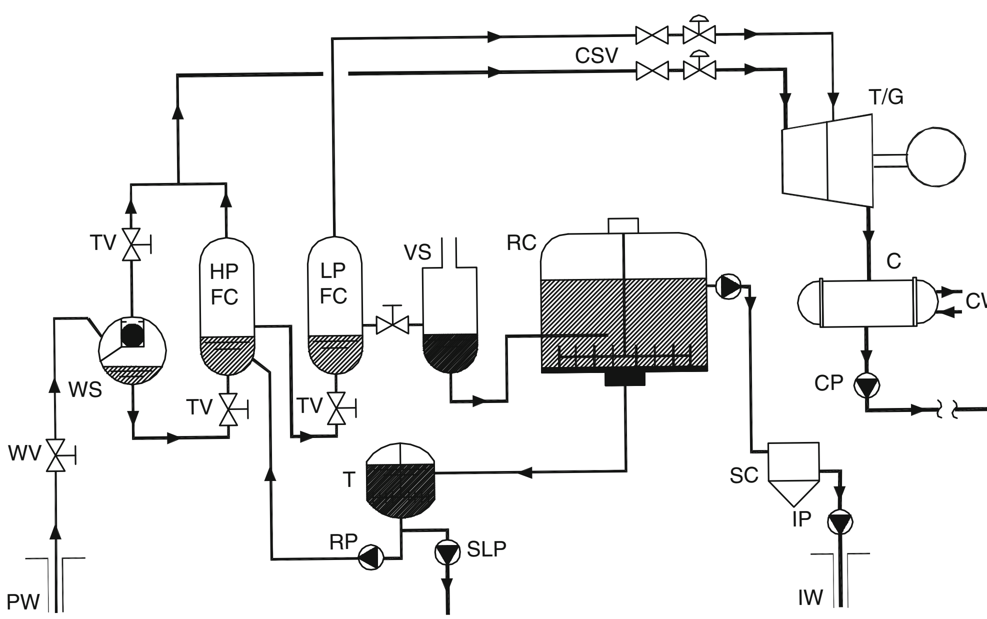
Geothermal Power Conversion Technology. Figure 76 Process diagram for combined single- and double-flash station

This equation shows that the heat extracted from the waste brine is equal to the heat absorbed by the Organic Rankine cycle working fluid, assuming perfect insulation on the heat exchangers. After solving for the working fluid flow rate it is found:

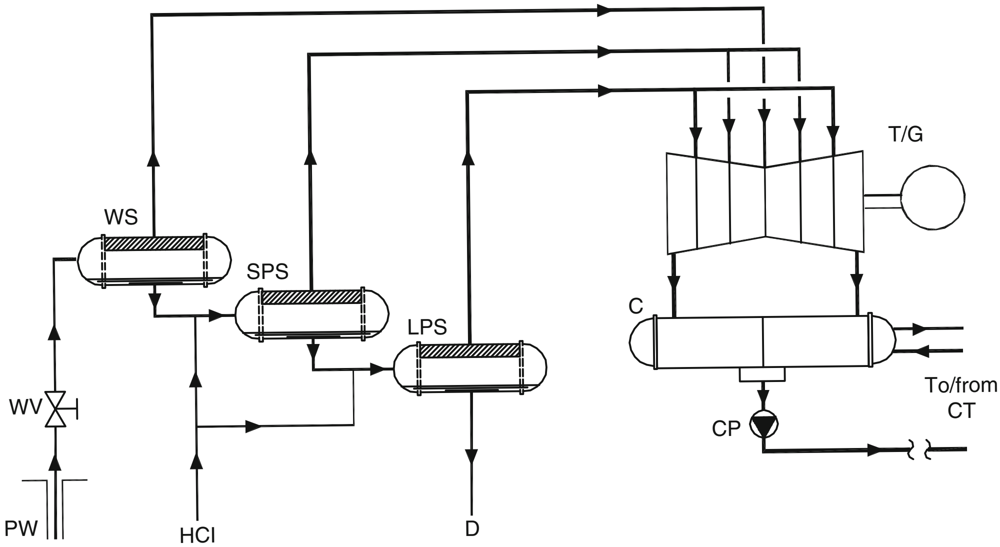
$$\dot{m}_{wf} = \dot{m}_b(1 - x_2)\left[\frac{c(T_3 - T_2)}{h_a - h_c}\right] \qquad (83)$$

Since the state points 1, 2, and 3 for the flash unit are fixed and the new state point 7 is subject to the constraint imposed by silica precipitation, only the Organic Rankine cycle parameters are open for assignment.

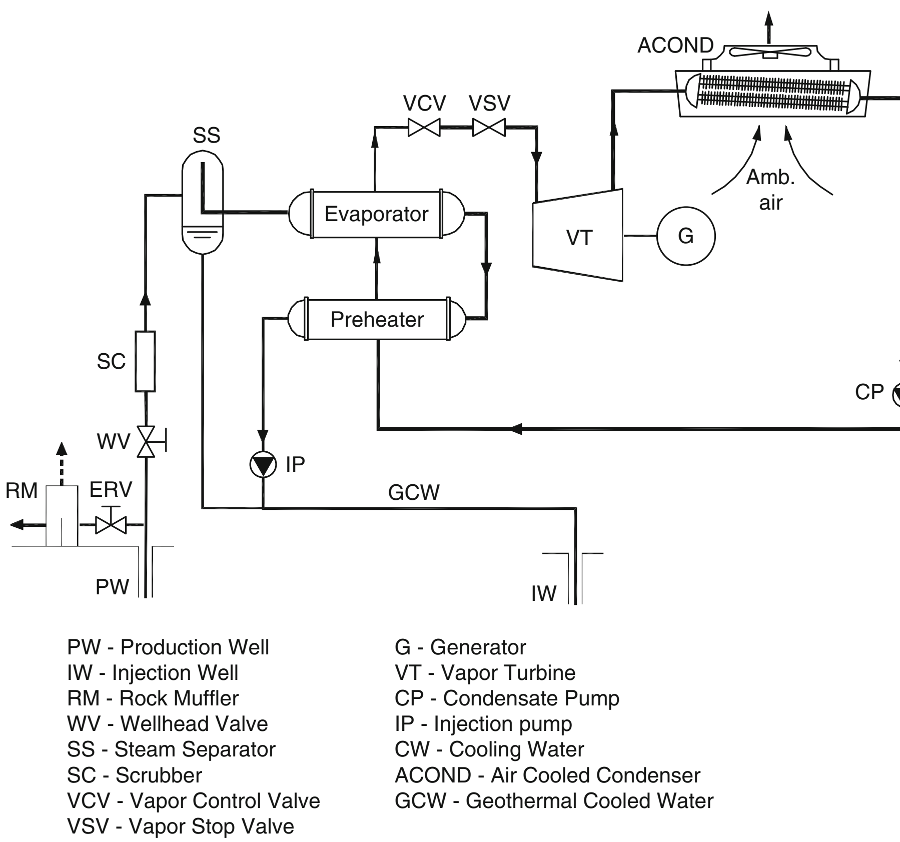
Geothermal Combined Cycle Power Stations In case of high enthalpy dry steam or vapor dominated sources the use of condensing steam turbines present a number of disadvantages. First the high humidity in the many stages of the low pressure turbine portions lead to efficiency loss and erosion/corrosion of the blades. Secondly if non-condensable gases are present use of vacuum pumps is necessary to avoid efficiency loss due to back pressure and reduction of the heat transfer coefficient of condensation. Using only the high pressure part of the condensing steam turbine (also called “back pressure steam turbine”) and using



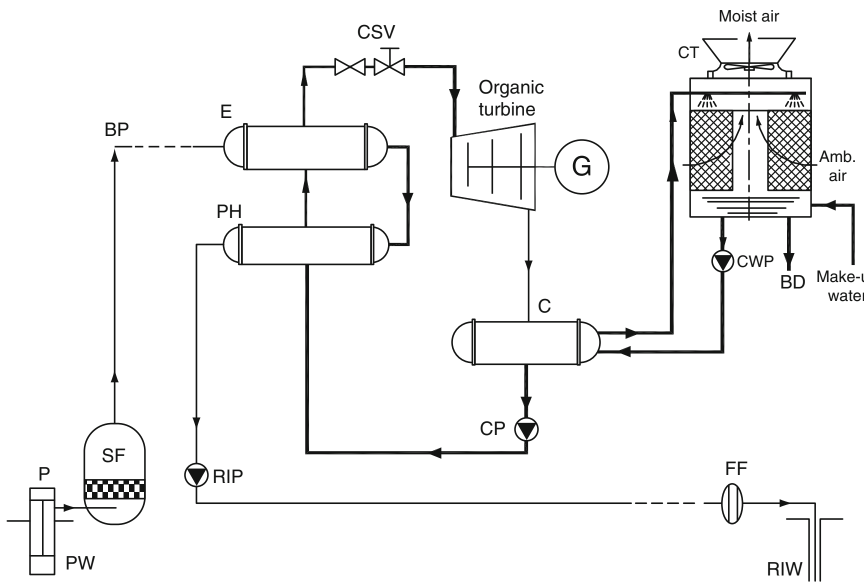
Geothermal Power Conversion Technology. Figure 77 schematic flow diagram for a FCRC power station, after [35, 69]



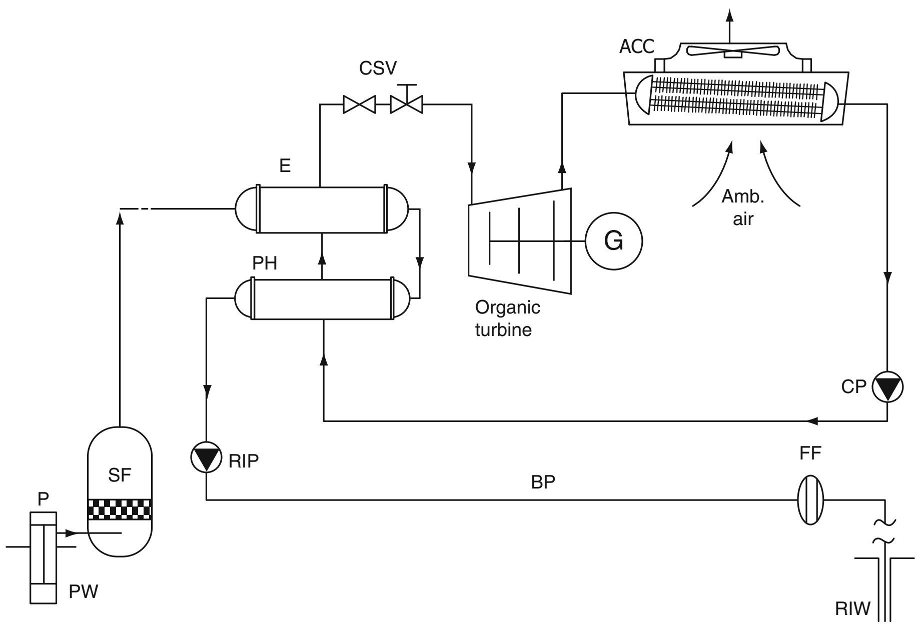
Geothermal Power Conversion Technology. Figure 78
Flow diagram for pH-Mod power station



Geothermal Power Conversion Technology. Figure 79
Binary cycle operated by flashed steam



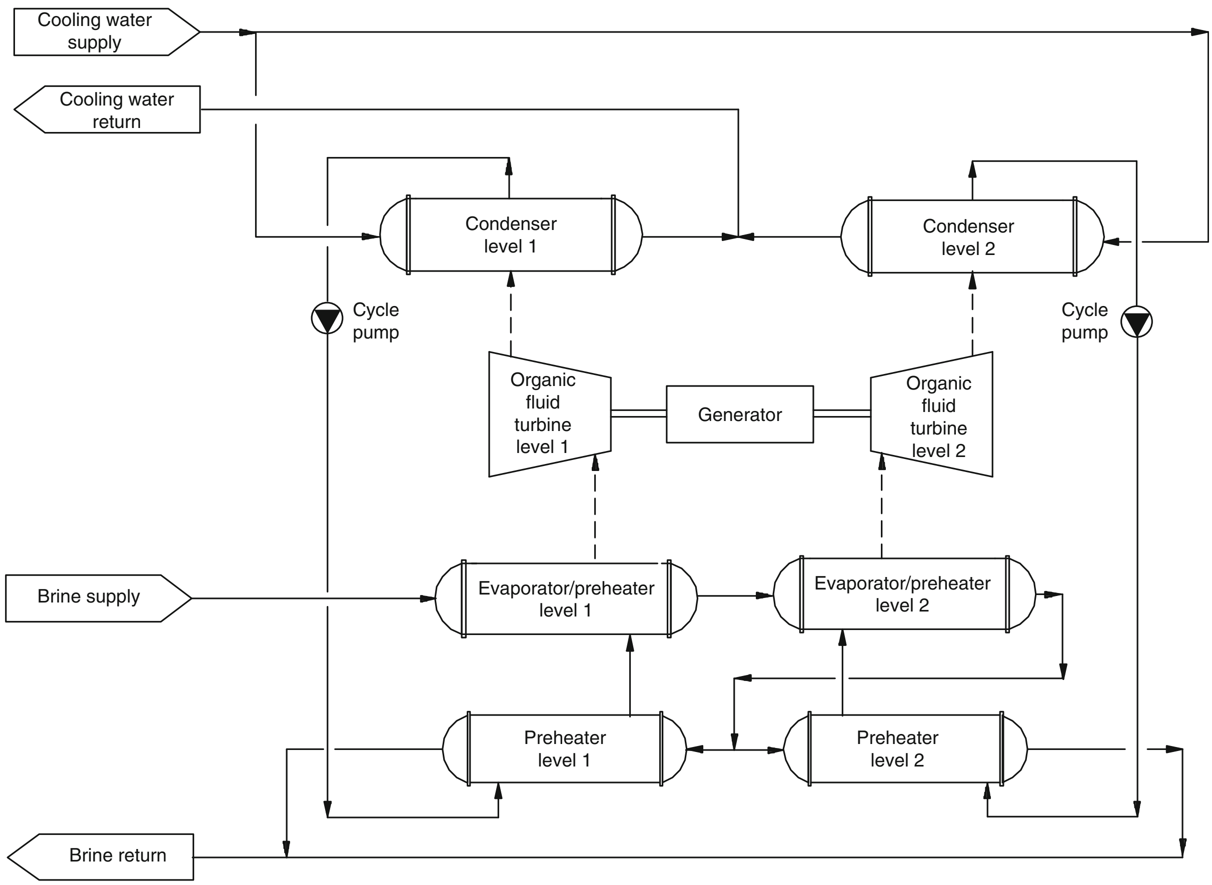
Geothermal Power Conversion Technology. Figure 80
Simplified schematic of a water-cooled binary geothermal power station [35]



Geothermal Power Conversion Technology. Figure 81
Simplified schematic of an air-cooled binary geothermal power station [61]

the exhaust steam as the heat source for the evaporator of an Organic Rankine cycle [82], we get a geothermal combined cycle Fig. 94 which avoids the above drawbacks of condensing steam turbines.

The collected brine at the moisture remover MR exit is dumped (if small quantity), or added to the condensate exit or delivered to the reinjection wells, depending on the quantities and temperatures of the brine.



Geothermal Power Conversion Technology. Figure 82
Integrated Two Level (ITLU) Power Station

The T-Q diagram of the Organic Rankine cycle (Fig. 95) will be the same as given before for the two-phase power station.

Geothermal combined cycle configuration avoids both drawbacks: steam expansion in the back pressure steam turbine is smaller limiting the wetness of the steam and its effects while the partial pressure of the non-condensable gases (NCG) is small and so is its effect on the condensation in the condenser/vaporizer of the Organic Rankine portion of the cycle. An additional advantage is that the NCG is above the atmospheric pressure, therefore can be ejected without the need of vacuum pumps or reinjected with the condensate into the injection well. Another advantage is that the use an air-cooled condenser on the ORC is more cost effective than on a condensing steam turbine.

Use of a Back-Pressure Steam Turbine Another approach for a moderate enthalpy two-phase heat source is the use of a back-pressure steam turbine which generates extra power from excess steam not required for the ORC evaporator.

Low-pressure steam exiting the back-pressure steam turbine (Fig. 96) is used to partially preheat the organic fluid.

The gap between the organic fluid steam and the preheating line could be filled more efficiently by a multistage (two or more) back-pressure steam turbine, with steam extraction between the stages. The number of stages takes into account the process trade-off optimization between higher efficiency and the complication (and cost) of the system.

A system based on the above cycle is now operating in the 20 MW Amatitlan geothermal

Geothermal Power Conversion Technology. Figure 83
Photo of 40 MW Heber ITLU Power station (Courtesy of ORMAT)

project in Guatemala (station photo is given in Fig. 97 and the station scheme in Fig. 98).

Geothermal Integrated Combined Cycle Power Stations When a bottoming Organic Rankine cycle is integrated with an air-cooled combined cycle, the result is a station with practically zero emissions. An integrated CC single-flash-binary station is shown schematically for water-cooled system in Fig. 99 [73] while Fig. 100 shows the same concept for air-cooled system [78] with three separated turbines. The process diagram is in two parts, the main upper combined cycle and the bottoming ORC portion. Geothermal steam first drives the back-pressure steam turbine and then is condensed in the upper ORC evaporator (E in Fig. 99). The two turbines in the upper part of the station may be connected to a common generator.

The separated brine (state 3) is used to preheat and evaporate the working fluid in the bottoming ORC. Noncondensable gases flow with the steam through the steam turbine ST into the evaporator where they are isolated, removed and compressed for recombination with the waste brine prior to reinjection. The brine holding tank (BHT) collects all the steam condensate, waste brine and compressed gases that go back into solution (Fig. 99).

In principle, this station has no emissions to the surroundings. The only environmental impact is the heat rejected to the atmosphere from the Organic Rankine cycle condensers. The scheme shows air-cooled condensers but water-cooling is an option.

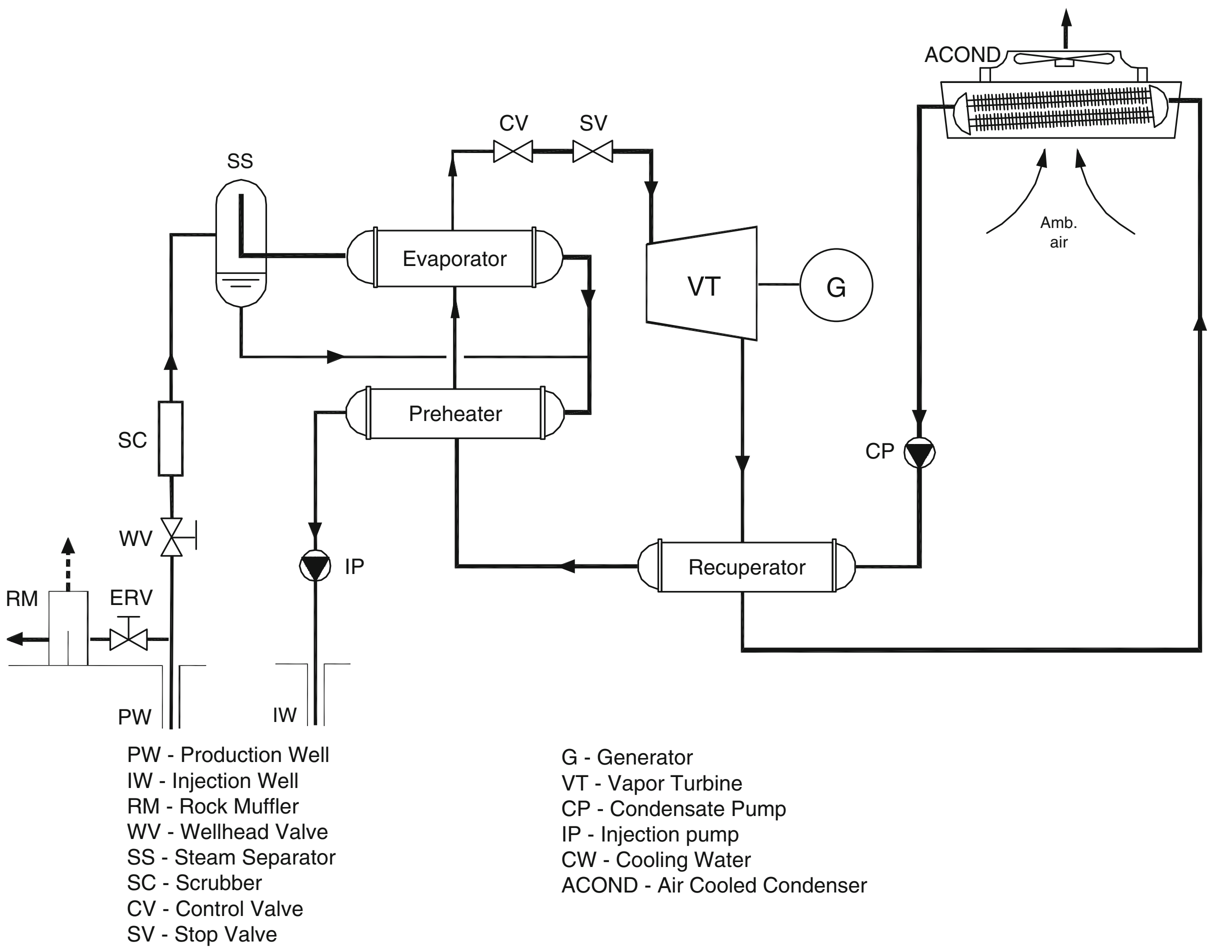
This configuration was first used in 1992 in the 30 MW Puna power station in Hawaii, then in the 125 MW Upper Mahiao in the Philippines (Fig. 101), 100 MW Mokai 1 and 2 in New Zealand.

An example for an integrated combined cycle station is given also by DiPippo [73].

Combined Heat and Power

Iceland In most geothermal sites the option for utilization of the residue heat energy contained in the waste brine does not exist. The main reason is the distance from population centers. Iceland is one of few examples where heat can be used for district heating and similar usage.

The Svartsengi geothermal area is close to the town of Grindavik on the Rekjanes peninsula and is part of an active fissure swarm, lined with crater-rows and open fissures and faults. The high-temperature has an area of 2 km^2 and shows only limited signs of geothermal activity at the surface. The reservoir contains much energy with at least 8 wells supplying the Svartsengi



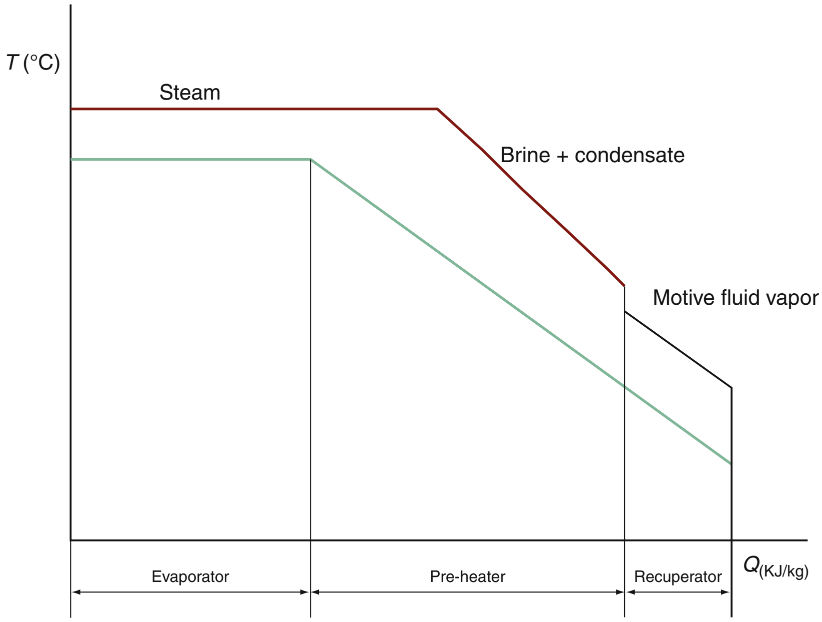
Geothermal Power Conversion Technology. Figure 84
Recuperated Organic Rankine cycle in two-phase binary power station

Power Stations with steam [79]. The steam is not useable for domestic heating purposes and heat exchangers are used to heat cold groundwater with the steam. Some steam is also used for producing 16.4 MW_e of electrical power, see Fig. 102 bottom. Figure 102 top shows the distribution system piping of hot water to nine towns and the Keflavik International Airport. The effluent brine from the Svartsengi Stations is disposed of into a surface pond, called the Blue Lagoon. This is popular for tourists and people suffering from psoriasis and other forms of eczema seeking therapeutic effects from the silica-rich brine.

In 1969, the Grindavik municipal council decided to do a study of harnessing geothermal energy in the Svartsengi area to heat houses in the village. The wells drilled at that time, 240 and 430 m deep, looked very promising. There was some disappointment as it was revealed that:

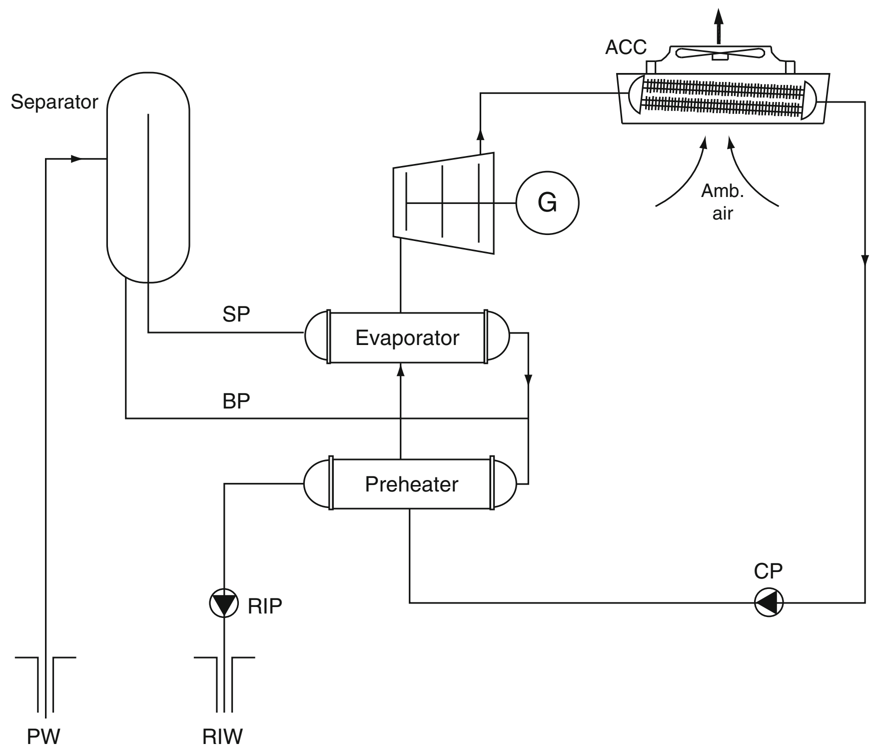
- This was a high-temperature geothermal area (i.e., with temperatures rising to more than 200°C at less than 1,000 m depth (to hot for domestic usage).
- The geothermal reservoir contained water with about two thirds of the salinity of the sea.

Due to the level of salinity and the high temperature of the water, it was clear that it would not be possible to utilize the geothermal fluid directly as had been the case in Reykjavik and most other places in Iceland. What was needed was the development of a method of heat exchange to facilitate the utilization of the geothermal power.

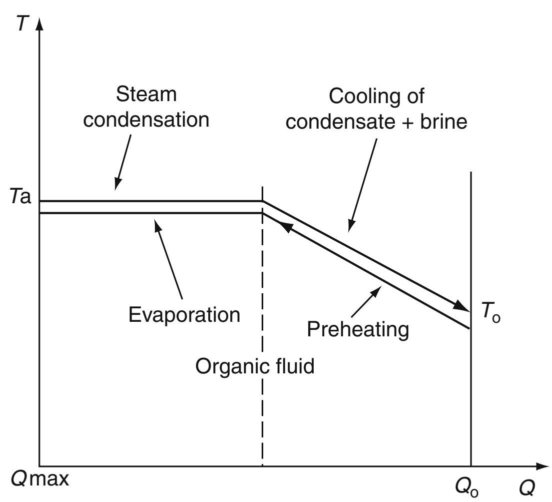


Geothermal Power Conversion Technology. Figure 85
Recuperated ORC in two-phase binary power station

Geothermal Power Conversion Technology. Figure 86
Two-phase 14 MW Ribeira Grande power station in the Azores (Courtesy of ORMAT)



Geothermal Power Conversion Technology. Figure 87
Two-phase binary power station

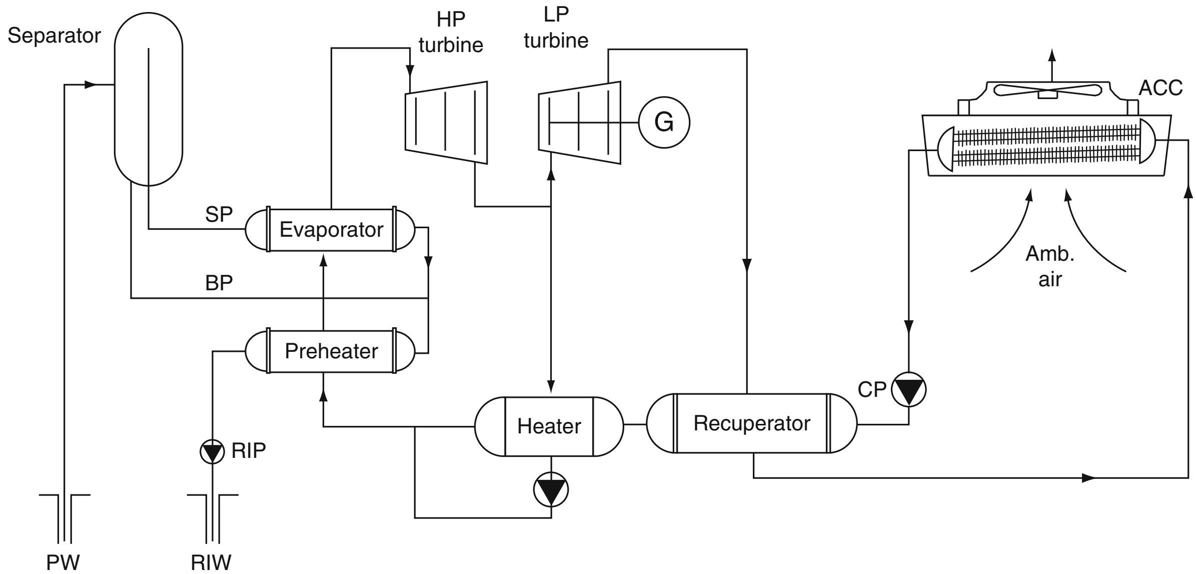


Geothermal Power Conversion Technology. Figure 88
T-Q diagram of a two-phase binary power station

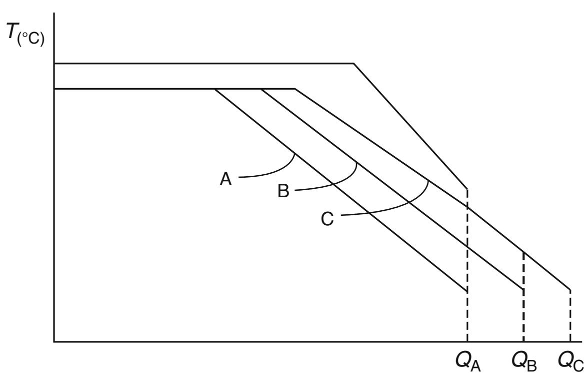
Rogner Hotel in Austria The 250 kW geothermal project at Bad Blumau is the first geothermal project developed in Austria by the private sector following the deregulation of the electricity industry in this country. Besides its private ownership structure, the project is unique due to its ability to generate electrical power and district heating by using a low-temperature geothermal resource. The unit is shown in Fig. 103.

The air-cooled ORMAT® Energy Converter (OEC) CHP module has been in commercial operation since July 2001. With an annual availability exceeding 99%, the station delivers about 1,300,000 kWh annually to the local grid. The geothermal CHP module utilizes brine at ~110°C available from a 3,000 m deep production well. Exiting the OEC unit at a temperature of ~85°C, the brine is then fed into the district heating system providing heat for the Rogner Bad-Blumau Hotel and Spa. The geothermal brine is returned from the district heating system and injected into a 3,000 m depth well.

The system is a pollution-free, unattended operating power generation module, which averts about 1,000 tons of CO_2 emissions annually.



Geothermal Power Conversion Technology. Figure 89
Secondary Organic cycle with LP partial vapor admission



Geothermal Power Conversion Technology. Figure 90
T-Q diagram of the high enthalpy secondary organic cycle

Experimental Power Stations

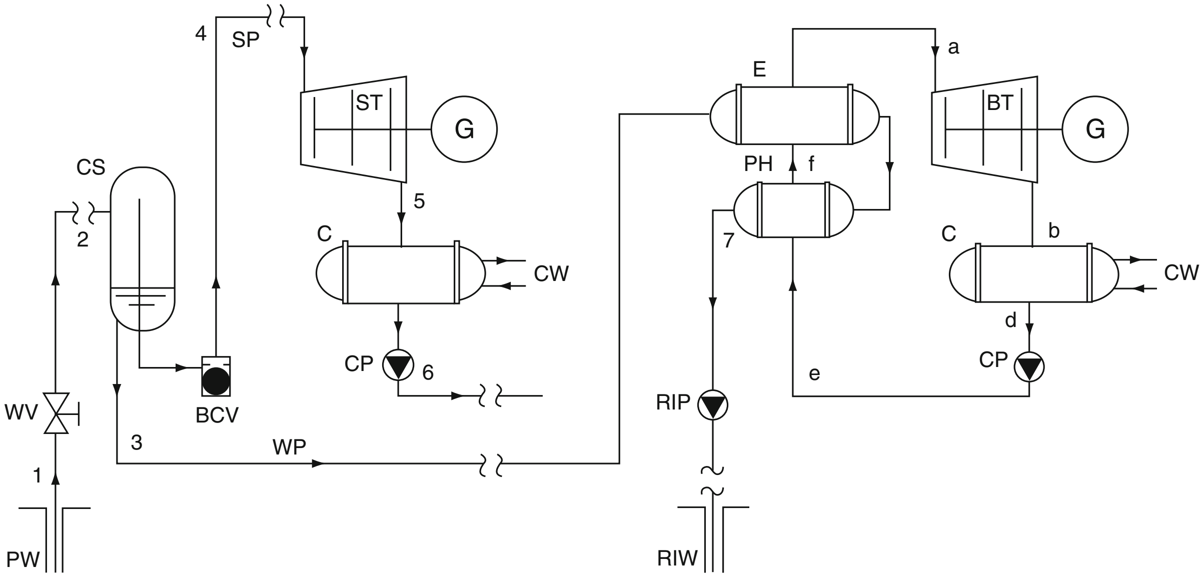
Dual-Fluid Organic Rankine Cycle

The first binary station in the USA was the Magmamax station at East Mesa in California's Imperial Valley. The station was a 12.5 MW station that began operation in 1979 using a dual-fluid cycle (two different hydrocarbons were used in interlocking Rankine cycles). One a subcritical cycle and the other a supercritical cycle [83, 84]. The typical dual fluid system is shown in Fig. 104.

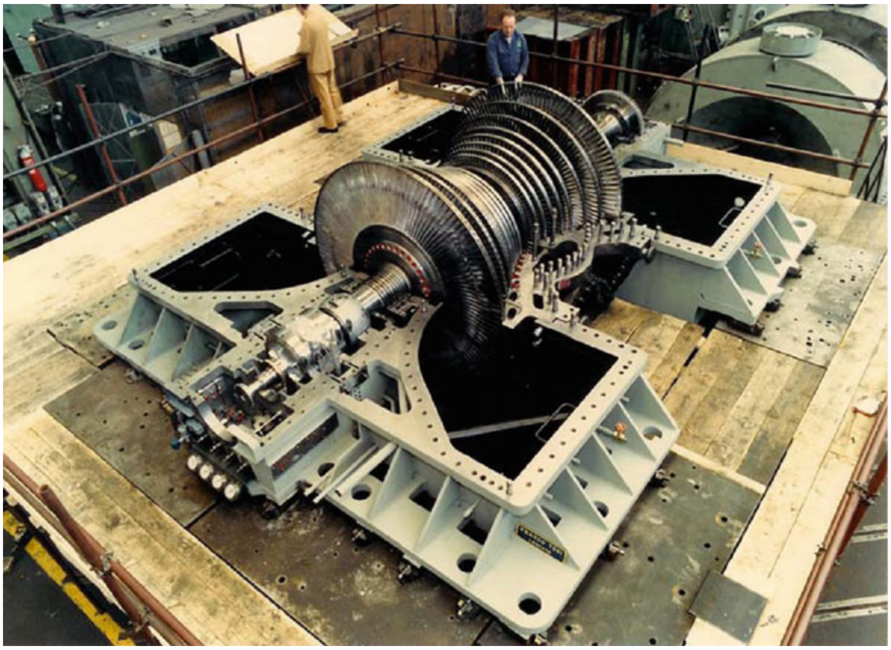
As with the dual-pressure cycle, incentive here is to create a good "match" between the brine and the working fluid heating-boiling curves. The temperature-heat transfer diagram Fig. 105, shows this relationship. The discontinuity between state points 5 and 11 arises from the internal heat transfer between the working fluids and does not involve the brine. From the diagram it is seen that the pinch point occurs between state b on the brine cooling curve and state 6, the bubble point for fluid 1. The near-parallelism between the brine and the working fluids in the preheaters means that the thermodynamic irreversibilities will be low, as will the loss of energy during the heat transfer process in those components. Since the average temperature difference in the fluid 1 evaporator is relatively large, it will be associated with a higher energy loss.

If fluid 1 is raised to a supercritical pressure before entering its preheater, the temperature-heat transfer diagram would change dramatically, see Fig. 106.

The sharp corner at state 6 denoting the bubble point for fluid 1 has vanished. Fluid 1 now has a smooth heating curve taking fluid from a cool compressed liquid to a hot supercritical vapor. There will still be a point of closest approach between the two curves, but it is far less pronounced. This allows a good



Geothermal Power Conversion Technology. Figure 91
Combined single-flash and ORC station; after [69]



Geothermal Power Conversion Technology. Figure 92
Momotombo Franco Tosi 35 MW steam turbine (Courtesy of Franco Tosi)

Geothermal Power Conversion Technology. Figure 93
Ormat 9 MW ORC bottoming power unit (Courtesy of ORMAT)

match between the brine and the working fluids which results in lower energy losses and higher utilization efficiency for the cycle.

As already mentioned, the supercritical cycle has higher thermal efficiency. However, the pump work is using greater fraction of the net cycle work and is about 50% higher than for the subcritical cycle.

There are additional practical difficulties with a supercritical cycle. The higher pressures may require change of traditional use of shell and tube heat exchangers in the geothermal application where the brine flows in the tubes and the organic fluid in the shell side. This allows for practical operation of in-tube cleaning as may be required in brine flow during long operation. Also, once it is changed, thicker and more costly tubing in the heat exchangers is required.

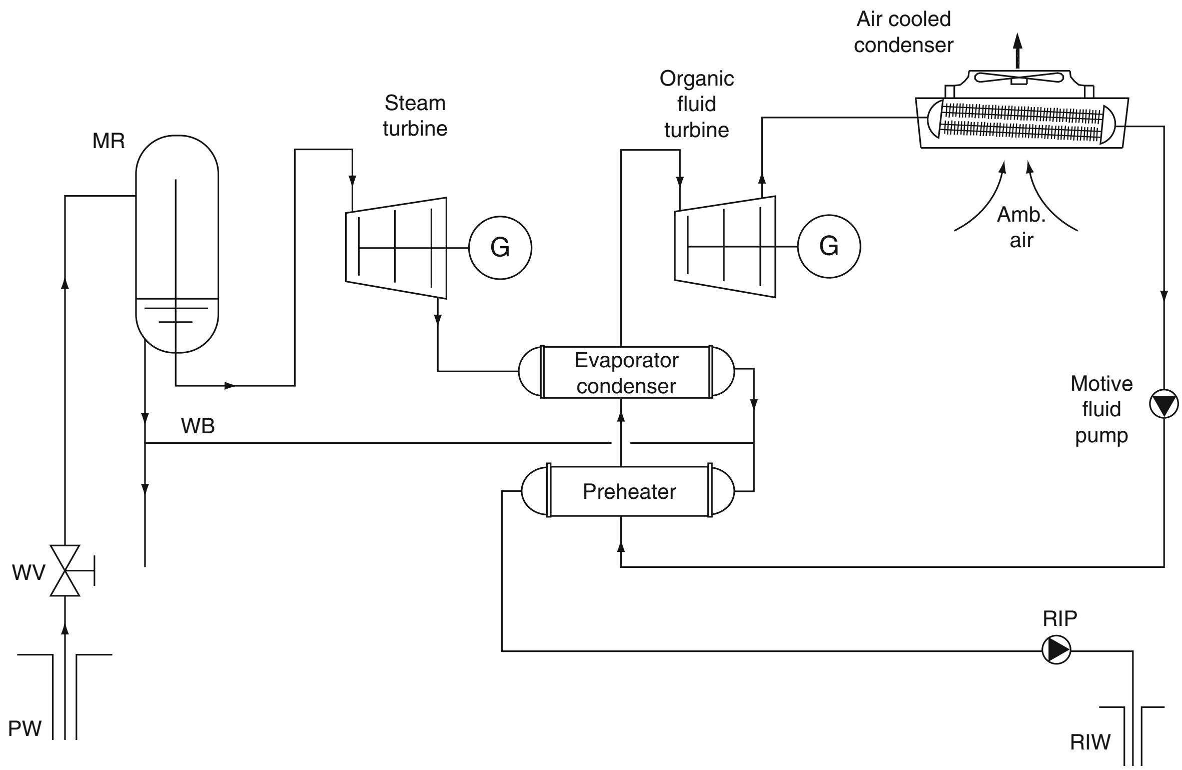
In both cases, the heat recovered from the condensation of fluid 1 is used for evaporation of the second fluid in E2. In a T-Q diagram between the two fluids there will be two parallel lines as given in Figs. 105b and 106b.

This was one reason why the original Magmamax station [83] placed the supercritical isobutane inside the tubes and the brine on the shell side of the heat exchangers.

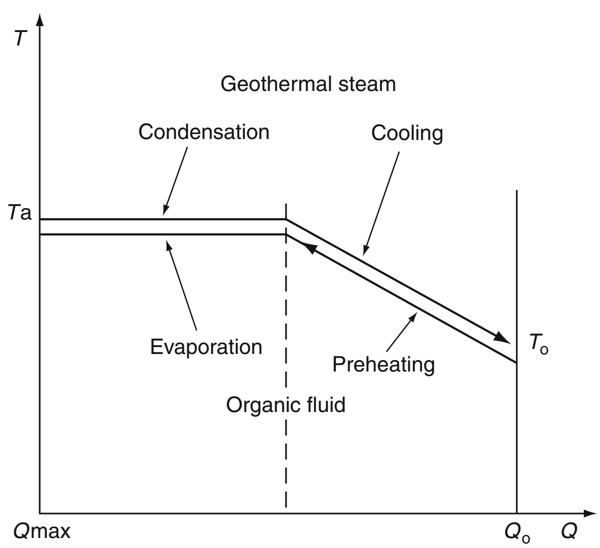
Kalina Cycle

Water-ammonia mixtures have long been used in absorption refrigeration cycles [85]. It was not until Kalina patented his Kalina cycle [86] that this working fluid was used for power generation cycles. A typical Kalina cycle, KCS-12, is shown schematically in Fig. 107. The features that distinguish the Kalina cycles (there are several versions) from other Organic Rankine cycles are as follows:

- The working fluid is a binary mixture of H_2O and NH_3.
- Evaporation and condensation occur at variable temperature (requires several heat exchangers).
- Cycle incorporates heat recuperation from turbine exhaust.



Geothermal Power Conversion Technology. Figure 94
Geothermal Combined cycle (GCC)



Geothermal Power Conversion Technology. Figure 95
T-Q diagram of the ORC part of the CC

- Composition of the mixture may be varied during cycle in some versions.

As a consequence, Kalina cycles show improved thermodynamic performance of heat exchangers by reducing the irreversibilities associated with heat transfer across a finite temperature difference. The heaters are arranged so a better match is maintained between the brine and the mixture at the cold end of the heat transfer process (where improvements in energy preservation are most valuable).

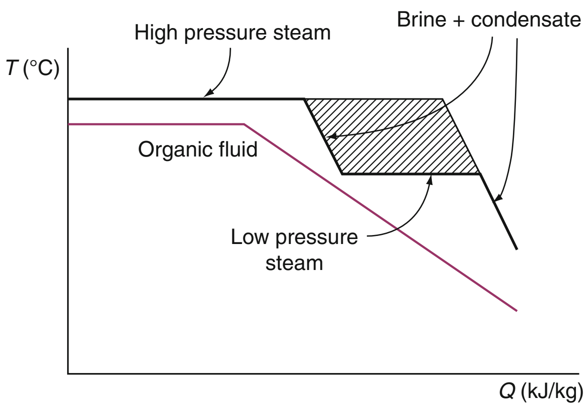
A reheater is needed because the water-ammonia mixture has a normal saturated vapor line, i.e., $dT/ds < 0$, leading to wet mixtures in the turbine. The station relies on good heat exchangers because more heat is transferred than in a supercritical binary station of the same power output. Bliem and Mines [87] showed that the Kalina cycle of Fig. 107 requires about 25% more heat transfer. A possible advantage to

using the recuperative preheaters is that they reduce the heat load on the condenser and cooling tower. The lower capital cost of a smaller condenser and cooling tower must be compared to the extra cost for the recuperators. Over the long haul, the resulting higher efficiency should mean lower operating costs.

The station is more complex than a basic binary station, particularly when a distillation column is used to vary the mixture composition. The simplest configuration of the Kalina cycle with variable working fluid composition is shown in Fig. 108. The separator S allows a saturated vapor rich in ammonia to flow to the turbine, thus permitting a smaller and less costly turbine than for a hydrocarbon working fluid. The weak solution (a liquid rich in water), is used in the preheater and is then throttled down to the turbine exhaust pressure before mixing with the strong solution to restore the primary composition. The mixture is then used in a recuperative preheater RPH prior to being fully condensed.

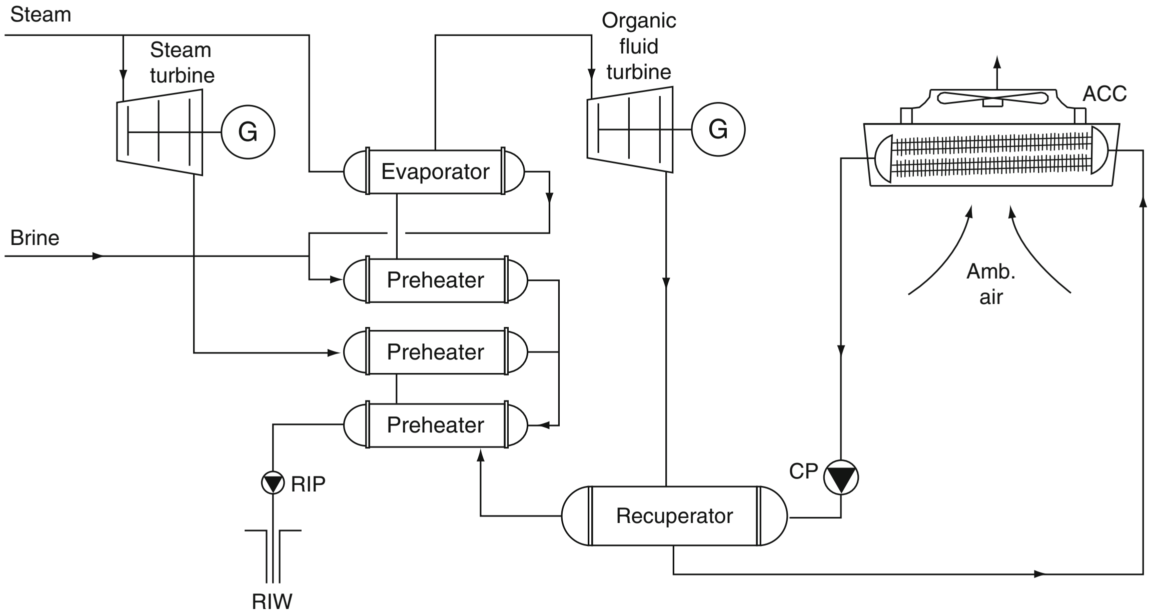
A possible difficulty for the Kalina cycle striving for high efficiency, is maintaining very tight pinch-point temperature differences in the heat exchangers. Also, the advantage of variable-temperature condensation is lessened because the condensing isobars of the ammonia-rich NH_3-H_2O mixtures used in power cycles concave upward, leading to a pinch-point. Thus, there are relatively large temperature differences at the beginning and end of the condensing process.

DePippo compared the Kalina cycle with a simple ORC cycle [88] (Second Law comparison) and concluded that for low temperature brine the Kalina cycle is about 26% more efficient than the ORC cycle. Paola Bombarda [89] compared the Kalina cycle against ORC and found that the dominant factor bringing high efficiency to the Kalina cycle is the system operating pressure.



Geothermal Power Conversion Technology. Figure 96
Preheating using exhaust in a back-pressure steam turbine

Geothermal Power Conversion Technology. Figure 97
20 MW Amatitlan Power Station in Guatemala (Courtesy of ORMAT)



Geothermal Power Conversion Technology. Figure 98
Block diagram of the Amatitlan Power Station

Kalina cycles operating at pressures lower that 100 bar will have lower efficiency than the ORC system, while those above 100 bar have higher efficiency. This is a disadvantage to the Kalina cycle as high pressure systems are likely to be more expensive in addition to the handling of >100 bar ammonia mixtures.

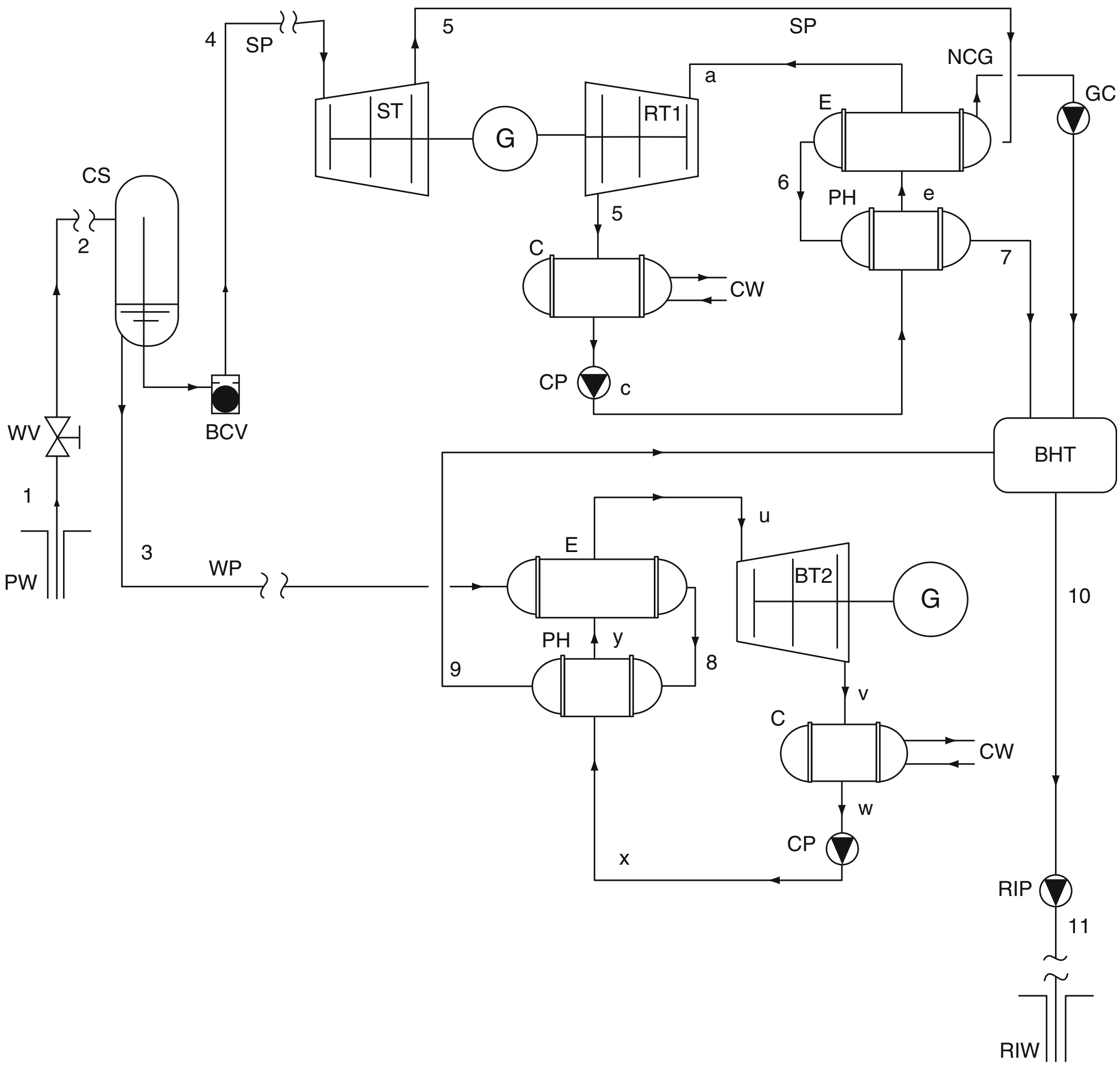
Geopressured Geothermal Systems

There are deep reservoirs holding geofluids at high pressure and temperature. Those of interest have pressures about 200–300 bar and temperatures ranging between 110°C and 200°C. The water, located at a depth of 3–5 km is high-salinity brine with large amounts of methane dissolved in it.

One location is the Gulf of Mexico, which is known because of the extensive oil/drilling that occasionally ends with water-dominated fluid instead of oil. The high pressurized liquid can drive a hydraulic turbine, then flow through binary unit evaporator and preheater to produce additional power. The solubility of methane depends on pressure, temperature and the salinity of the brine. Extracting the methane after the hydraulic turbine and transferring most of its heat to the organic liquid may give the best results. Test drills along the Louisiana coastline [90] and one actual methane extraction test made by the DOE in Pleasant Bayou in Texas proved the viability of the gas extraction, even if a hydro-turbine was not used in this case. A comprehensive work by Griggs [91] added valuable information for the utilization of geopressurized aquifers as source of energy. Nitschke and Harris [92] suggested the first use of the geopressurized hot water in a hydro-turbine (Pelton wheel) and then for large-scale water desalination. They suggested an MED desalination station because of its design that allows small temperature difference per effect. Methane is a by-product that may be used on-site but its economic value depends on local energy prices and is not a closed deal. The chemistry of the brine must be followed very carefully for fear of entering the solubility limit. Other locations of geopressured sites are known in Hungary [93] and China [94]. An option for direct utilization of the separated methane is described in section on "Hybrid Fossil Geothermal Systems."

Hybrid Geothermal Power Stations

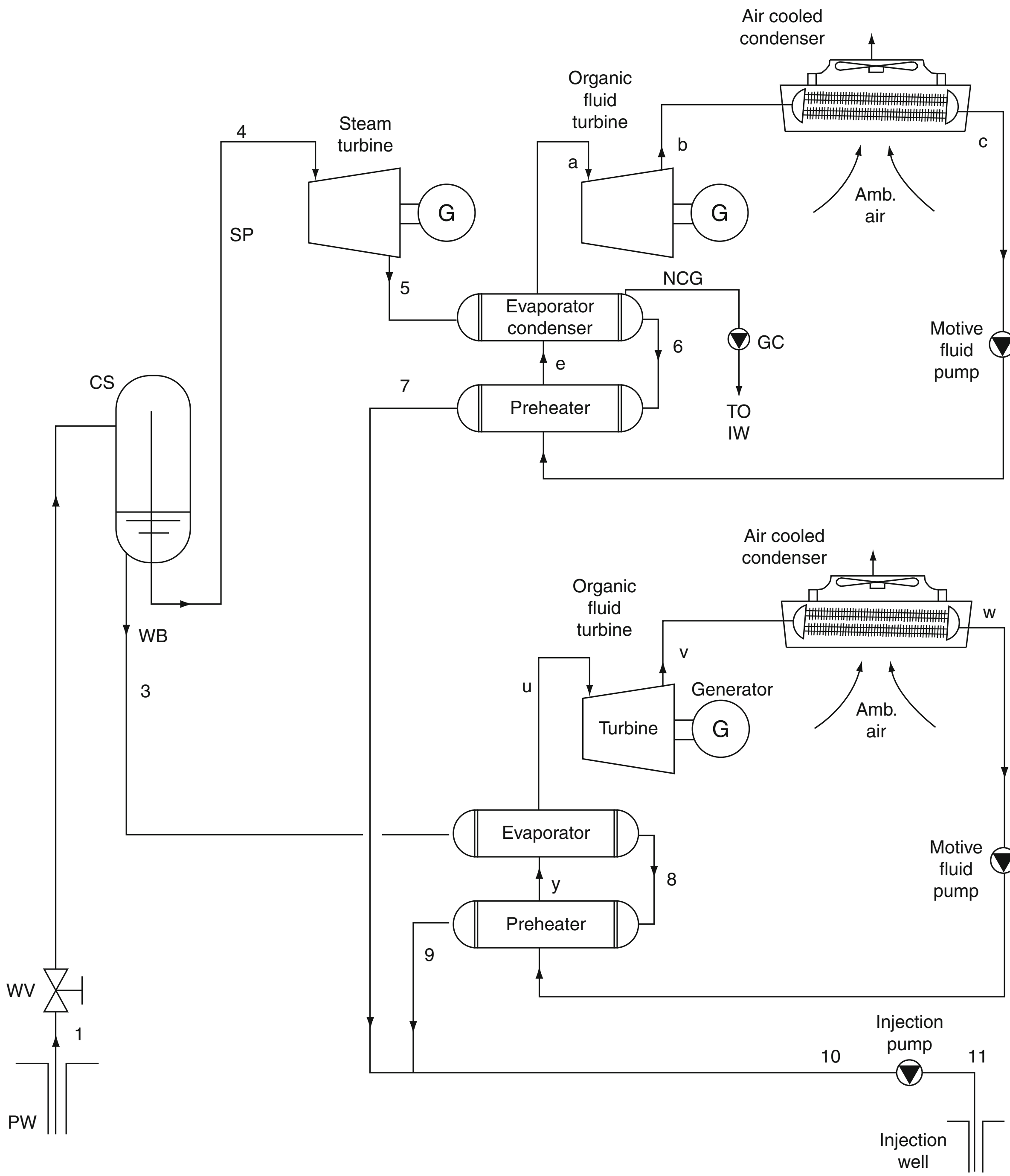
Hybrid Geothermal Power stations are stations in which the geothermal heat is supplemented by another heat source.



Geothermal Power Conversion Technology. Figure 99
Integrated geothermal combined cycle and bottoming ORC Power Station – water-cooled system

Hybrid Geothermal Fossil Fuel Power Station

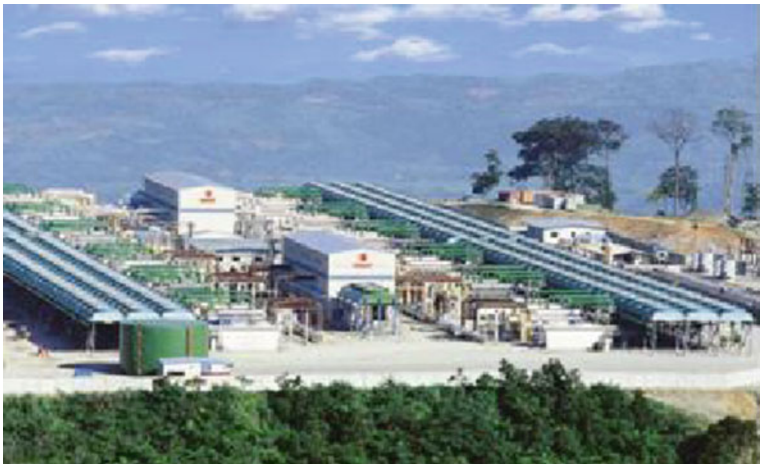
Geothermal steam, whether dry or flashed, is bound to expand into the wet zone and therefore its power production is somewhat limited. The idea of using fossil fuels for superheating and to enhance geothermal resources is not a new concept. A paper published in 1924 indicated that it was already suggested by P. Caufourier [95]. He proposed a hybrid power system in which hot water from a geothermal spring would be successively flashed four times and the generated steam superheated in a fossil fired superheaters prior to being admitted to a multi-pressure turbine. Thermodynamic analysis by DePippo [96] showed that the system which burns fuel for that purpose only is not economical. A different approach suggested usage of heat recovery of a gas-operated gas turbine for superheating of geothermal steam in The Geysers geothermal field [97]. Such a hybrid system would have the highest utilization of fossil fuel as compared with regular GT power generation. For additional



Geothermal Power Conversion Technology. Figure 100
Integrated geothermal combined cycle and bottoming ORC Power Station – air-cooled system

information on superheating of geothermal steam see studies by Brown University [98, 99].

In geopressured wells there is usually some natural gas content that is separated before or after usage of the heat energy in binary or flash steam cycles. The gas can be used in a gas engine such as gas turbine and the exhaust heat utilized for the geothermal steam superheating as previously mentioned. Such systems



Geothermal Power Conversion Technology. Figure 101
125 MW Upper Mahiao Geothermal Power Station in the Philippines (Courtesy of ORMAT)

were analyzed by Chang and Williams [100] in a work sponsored by the DOE 1985.

Hybrid Geothermal Biomass Power Station

The concept is similar to the hybridization with fossil fuel, but because of generally lower combustion temperature of biomass, the thermodynamic draw-back is smaller. The geothermal resource is used to preheat the motive fluid while the biomass is used to evaporate the motive fluid. Although the exhaust heat from biomass combustion may provide all the preheating of the motive fluid making the geothermal resource use redundant, however because the high dew point of exhaust gases from biomass combustion there is room for the geothermal heat for preheating. A few such power stations were proposed and it seems that at least one was constructed.

Hybrid Geothermal Solar Power Stations

This hybridization presents three advantages. The first is thermodynamic, by providing all the heat of evaporation from the solar collector, the efficiency of the utilization of the sensible heat of the geothermal reservoir, is improved: see paragraph “Available energy” and Figs. 6 and 7. The second is an improvement of the load following of the station: more power produced during peak hours. Thirdly the economics is improved by a better use of the interconnecting facility and of the personnel. The outline of such a system is shown in Fig. 110.

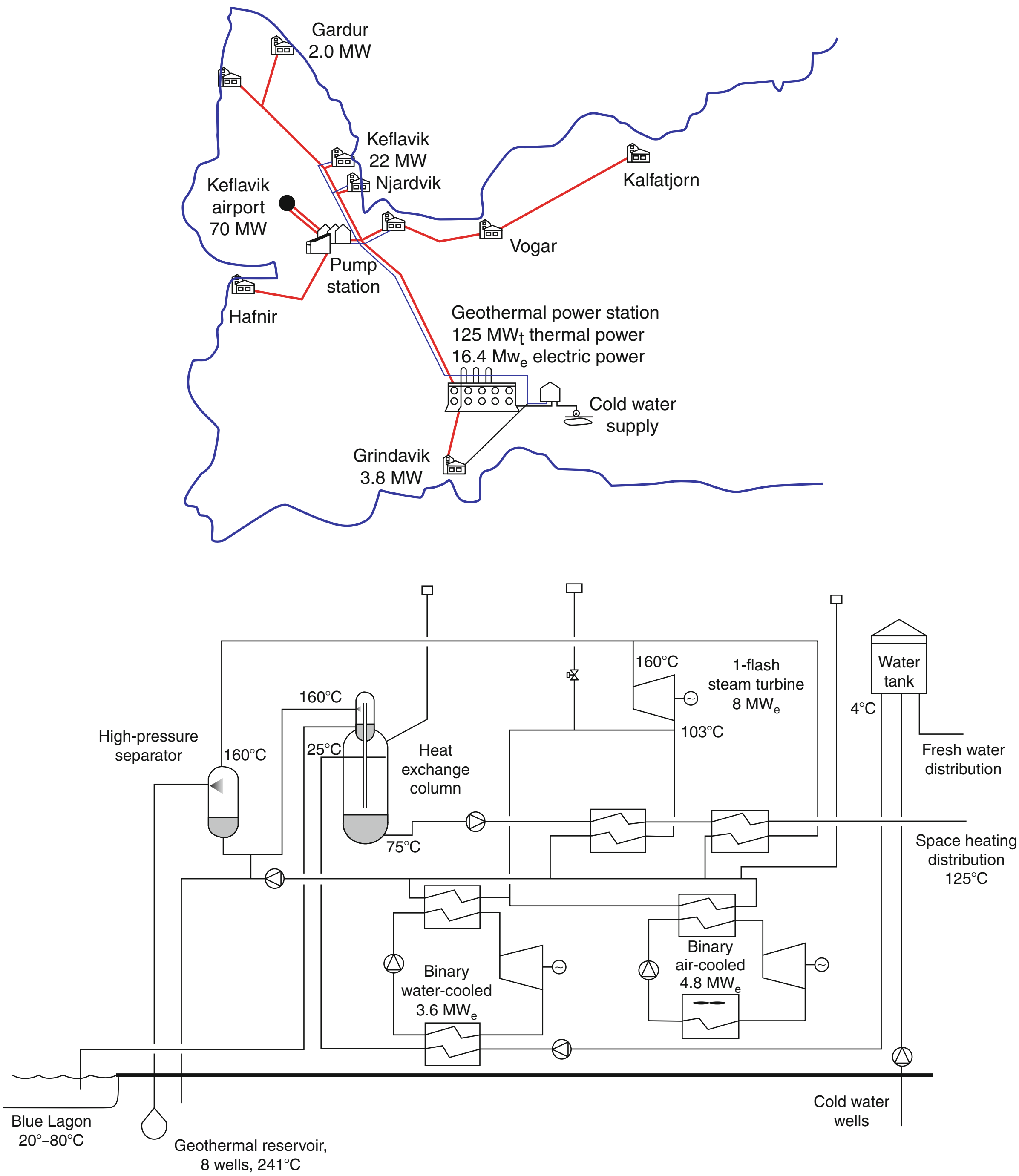
Power Stations for Enhanced Geothermal Systems (EGS)

MIT report states that the majority of geothermal energy within drilling reach that can be utilized for power production is in dry and nonporous rock [101]. Drilling into hot rock formations and creating cavities to accommodate large enough heat transfer area for heating of water are considered as enhanced geothermal systems (EGS). Substantial progress has been made in developing and demonstrating certain components of EGS technology in the USA, Europe, Australia and Japan. Further work is needed to establish the commercial viability of EGS for electrical power generation, cogeneration and direct heat supply.

A seperate, specific part of the present publication deals with the resource development, therefore attention is given here to the energy conversion system only.

Assuming that the build-up of the resource has been made. Water travelling through the fractures in the rock captures the rock heat and emerges from the production well accompanied by dissolved solids, large amount of particles and possibly noncondensable gases (NCG). Tests made in Japan [102–105], USA [106], UK [107] and other countries range the out-coming water temperatures between 150°C and 270°C.

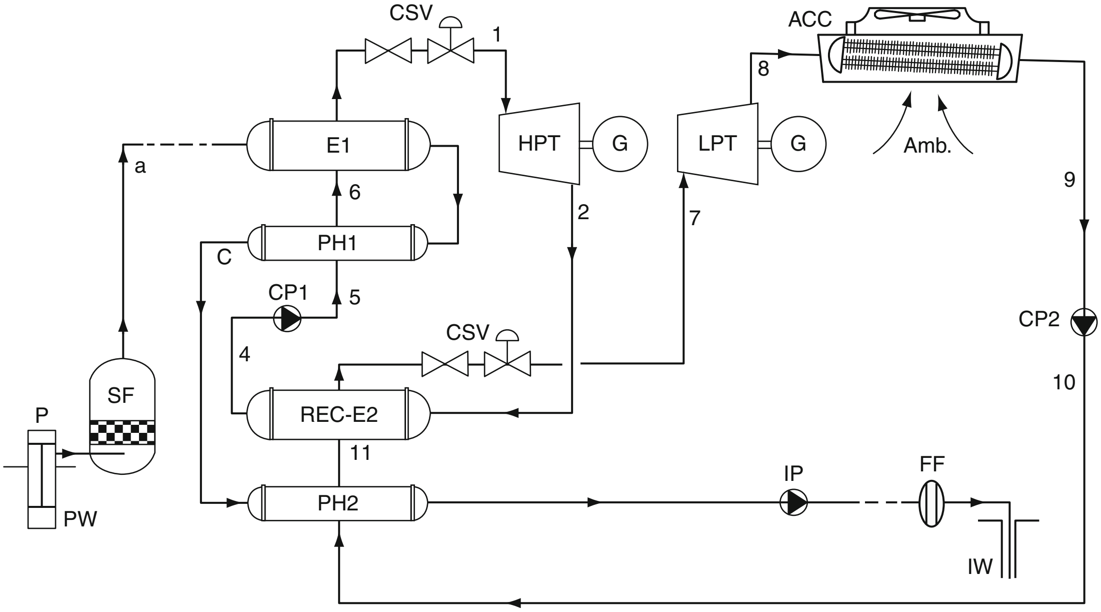
The lower-temperature brines are suitable for power generation via binary systems. The higher-temperature brines (above 200°C) are flashed, cured



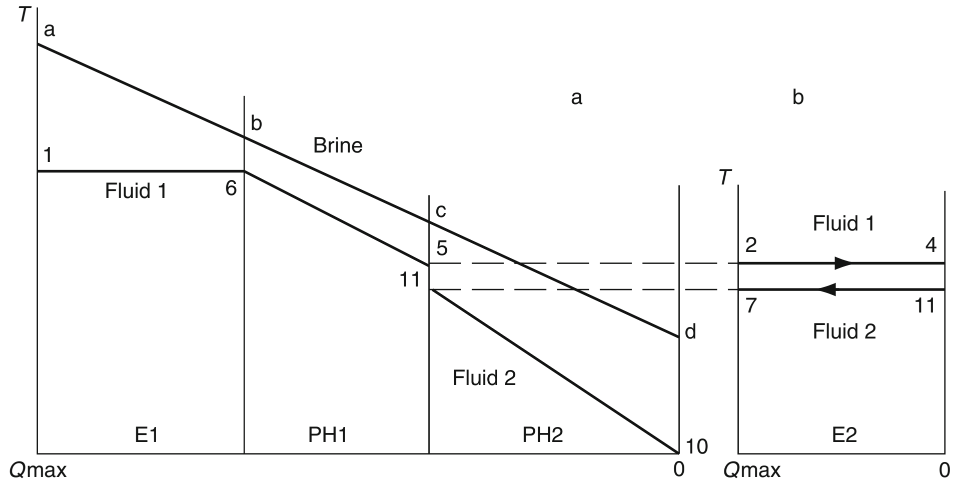
Geothermal Power Conversion Technology. Figure 102

The Sudurnes Regional heating system layout and flow diagram for Svartsengi Power Station

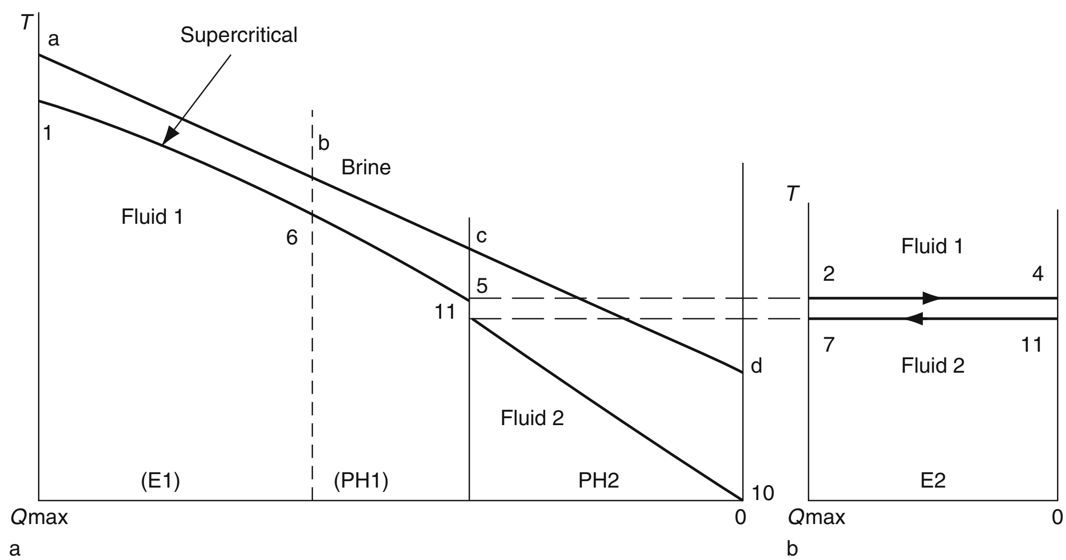
Geothermal Power Conversion Technology. Figure 103
250 kW Geothermal ORC Power Unit at Rogner Hotel and Spa, Bad Blumau, Austria (Courtesy of ORMAT)



Geothermal Power Conversion Technology. Figure 104
Scheme of dual fluids binary power station



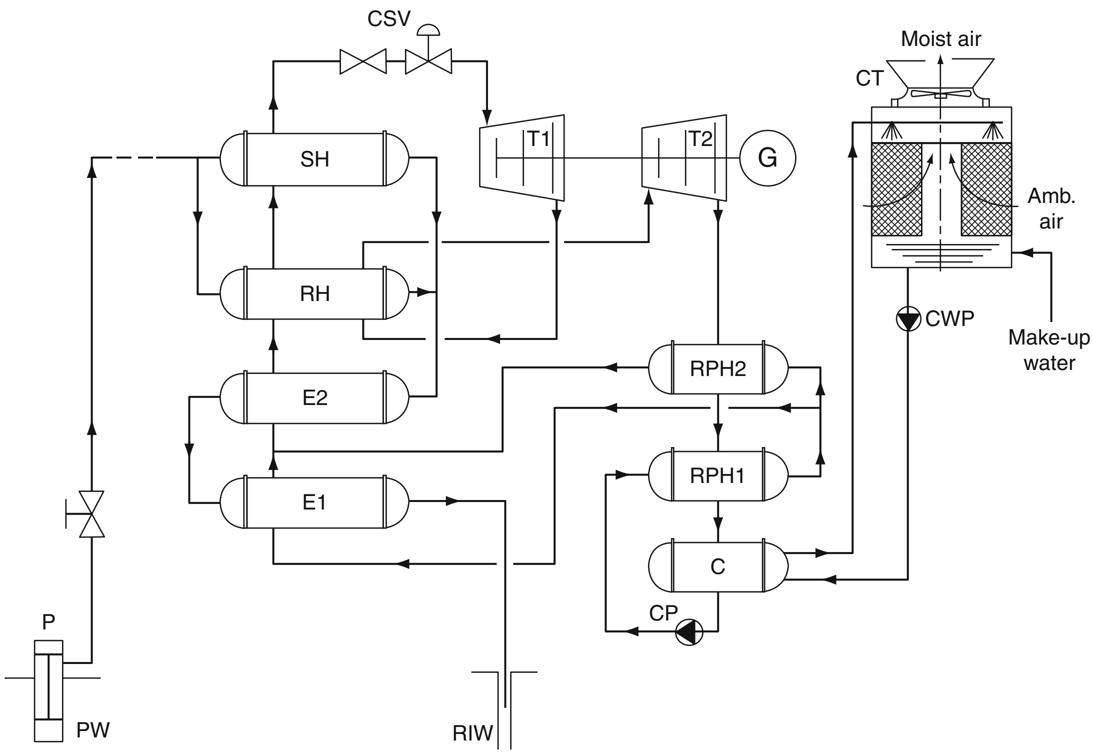
Geothermal Power Conversion Technology. Figure 105
T-Q diagram of dual organic fluids in subcritical condition



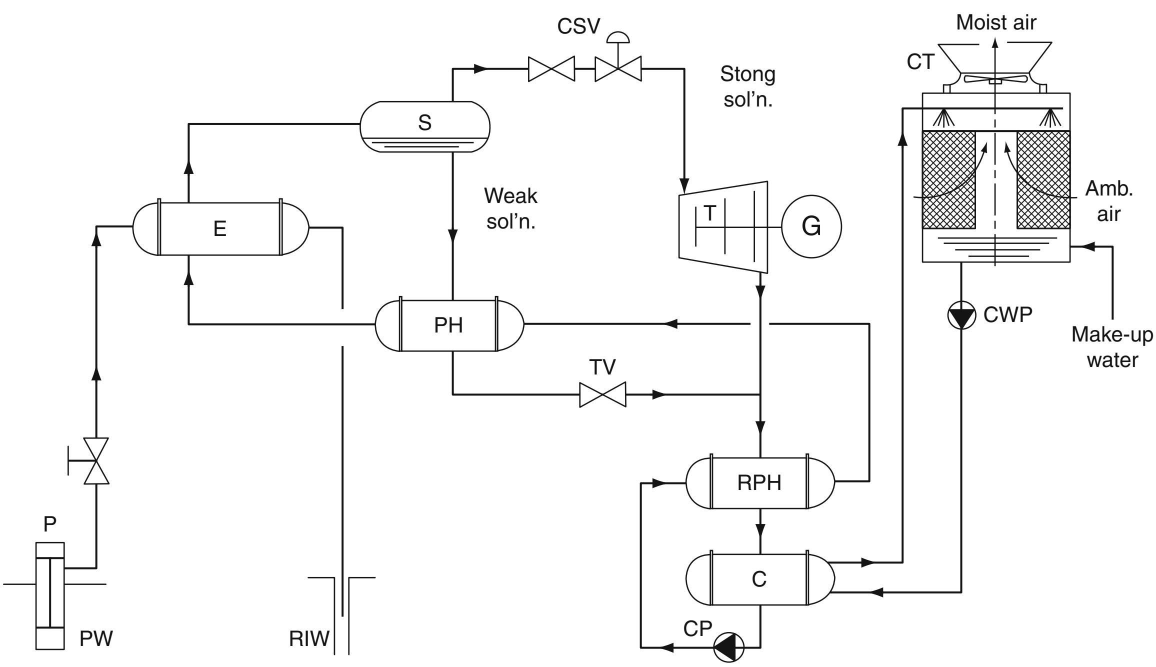
Geothermal Power Conversion Technology. Figure 106
T-Q diagram of dual organic fluids in supercritical condition

of NCG and particles and then can be directly used in steam turbines providing vapors free of aggressive components. However, due to the NCG problem and since the nature of dissolved materials in the brine may change in time, an indirect utilization by use of ORC binary stations is preferred. The air-cooled ORC stations are particularly well adapted to the EGSs. The somewhat higher installed cost of these systems is justified by environmental and long-term resource management considerations.

Most of the reported EGS stations are experimental with a status between planning, fundraising, drilling and partial operation (see list in [102]. The only partial EGS station in continuous commercial operation is in Landau, Germany using the Organic Rankine cycle [108].



Geothermal Power Conversion Technology. Figure 107
Typical Kalina cycle employing a reheater and two recuperative preheaters

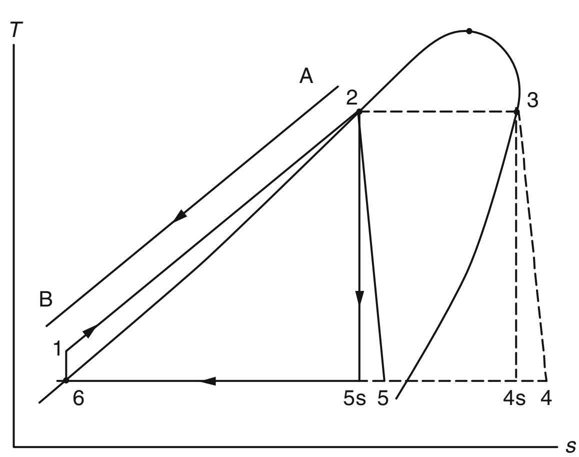


Geothermal Power Conversion Technology. Figure 108
Kalina cycle with variable composition of the water ammonia working fluid

Other Organic Rankine cycle stations are Soultz (France) [109], stations in Australia, Desert Peak and Newberry Oregon in the USA (being planned). The air-cooled ORC stations are particularly well adapted to the HDR/EGS. The fairly higher installed cost of these systems is justified by environmental and long term resource management consideration.

Trilateral Flash Cycle (TFC)

The Trilateral Flash Cycle (TFC) and its more recent "Smith" cycle [110] were developed for efficient utilization of HDR geothermal heat source. Because the work producing process is based on flash expansion of the liquid and the cycle is close to the thermodynamic trilateral ideal, it is a Trilateral Flash Cycle (TFC) system. The main feature as seen in Fig. 109 is to transfer the HDR heat (points A–B) to Organic liquid (points 1–2) and allow expansion in a two-phase expander (points 2–5) instead of the regular evaporator (points 2–3) and dry turbine expansion (points 3–4). This is a drawback due to the relative low efficiency of the two-phase expansion resulting from operation deep in the wet zone. The more advanced Smith cycle suggests various options of expansion procedures as the required ratio of expansion is above 100 and this cannot be achieved with the screw expander or even a radial turbine suggested by Smith. There is a two-phase expander in the first stage followed by separation



Geothermal Power Conversion Technology. Figure 109 Scheme of the trilateral flash cycle (TFC)

vessel from which the system proceeds in two parallel lines, one a two-phase expander and the other a vapor turbine which expands in the dry zone. Theoretical analyses and cost estimates are optimistic, but the development of a large and still not constructed expander is still required. Few of the expanding devices suggested for this and similar "total-flow" cycles will be described in section on "Total Flow Systems."

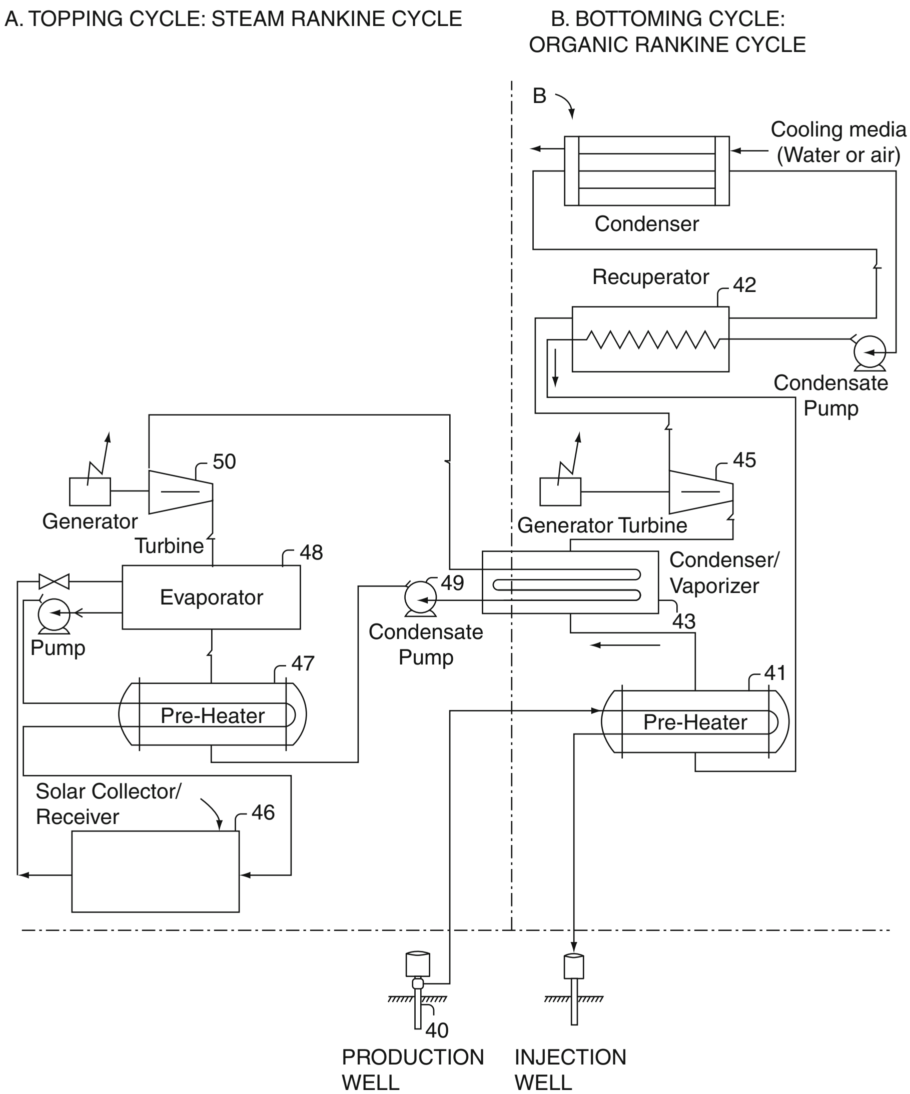
Total-Flow Systems

Utilization of the steam or brine geofluids is accompanied by irreversiblities that consume a significant portion of the available energy and include quite large cost of equipment for separation, flashing and expansion. New ideas for direct use of the geofluid are basically directed at the large saving in equipment cost, direct expansion with half of turbine efficiency but no flashing. The main present directions are:

1. Single-stage impulse turbine [111]
2. Positive-displacement expander (a helical screw expander called also "bi-phase expander" and rotary expander) [112, 113]
3. Rotary separator turbine [114].

Two-Phase Turbine A hybrid geothermal power station comprises in addition to the geothermal heat source a supplementary heat source such as biomass solar or even fuel. In a total-flow turbine the fluid expands from near the liquid line, while with a regular steam turbine the steam expands from near the saturation line. Comparing these two turbine cases between the same given temperatures (fluid high temperature and condensing temperature) it is found [111, 136] that the total-flow turbine efficiency can be about half the steam turbine efficiency for the same power production. Therefore steam turbines efficiency is in the range of 80%, with the best efficiency of single-stage impulse turbine still at 23%. However, the single stage impulse turbine is remarkably smaller and the system uses all the brine energy compared with only the flashed steam energy.

Positive Displacement: Helical Screw Expander The helical screw machine is usually used as a compressor in refrigeration cycles. It is also used as air compressor in stationary and mobile compression units. Due to the



Geothermal Power Conversion Technology. Figure 110
Hybrid Geothermal Solar Power Station (Courtesy of ORMAT)

screw shape of the twin rotors, pressure losses are small and high pressure ratio is obtained. If a high-pressure fluid is passed to the "exit" side of such a compressor then the expanding fluid will rotate the screw rotors. Tests with two-phase flow indicated that there are limitations to the rate of expansion caused mainly by the initial liquid content. Pre-flashing and partial flashing that changes the liquid–vapor ratio may diminish this issue. Tests conducted in the Unites States, New Zealand [112, 113] and in 1986 by Sprankle [115] were not continued.

The use of rotary expander used in passenger cars was considered by NEDO in Japan for the same task. A 300 kW prototype was built and tested in 1982, but there is no information on further tests.

Rotary Separator Turbine Here the two-phase flow (steam and brine) is separated in brine-driven primary turbine wheel. The steam is passed to the regular steam turbine for further expansion while the brine is drained from the system. The assumption is that the steam pressure is not significantly reduced by the above

separation. The overall energy achieved from the two turbine wheels did not exceed the regular steam turbine. Tests performed in Roosevelt Hot Springs in 1981–1982 by Cerini et al. [114] were unsatisfactory. Additional work was summarized by Hughes [116] in 1986 with no reports in the following years.

Future of Geothermal Energy

Background

The cited papers used in this review do not always agree on the direction of development and forecast of power generation capacity but it is important to bring up and present all views to the reader.

United States

At the Symposium on energy sources for the future, in Oak Ridge, Tennessee, held between July 7–25,1975, M. King Hubbert [117] presented a Survey of World Energy Resources. He was very skeptical about the future of geothermal energy. The total world installed geothermal power capacity in 1975 was approximately 1,500 MW, and in spite of optimistic forecasts by geothermal power enthusiasts, such as Tester and Milora [118] at the same symposium, he forecasted an increase in only "order of magnitude." As injection was hardly used at that time he claimed that in all likelihood most large installations will be comparatively short-lived, perhaps a century or so.

Today however, with deep-well explorations and successful injection programs there is a reassessment of the geothermal potential as reported at the World Geothermal Congress in Bali by Ruggero Bertani [123] in April 2010.

The report indicates that in the USA there are 9 states, all in the West, with operating geothermal power stations, and a total installed capacity of 3,093 MWe. The report estimated that by 2015 up to 5,400 MWe of capacity will be installed in the USA. This assumes conventional hydrothermal resources. The report assumes that known hydrothermal resources in Western USA have a potential to produce 9,000 MWe.

The most comprehensive estimates for the total US recoverable resource were produced by US Geological Survey (USGS) in the late-1970s. In 1978, USGS Circular 790 suggested that the total recoverable resource from identified geothermal prospects is roughly 23,000 MW and the total combined identified/unidentified resource base is as high as 150,000 MW. In 2008, the USGS revised its numbers to reflect lower temperature resources, apply confidence ratios to the numbers and make assertions based on 30 years of results in the field. As such, a new estimate suggested 95% confidence that identified systems can provide 3,675 MWe and 5% confidence that identified systems can provide 16,457 MWe. The new estimate suggested 95% confidence that undiscovered systems can provide 7,917 MWe and 5% confidence that undiscovered systems can provide 73,286 MWe [119].

In January of 2006, a comprehensive assessment was released by the Western Governors' Association (WGA) in its Geothermal Task Force Report. The assessment was performed as part of the WGA's Clean and Diversified Energy Advisory Committee (CDEAC). The report covered 11 western states (Alaska, Arizona, California, Colorado, Hawaii, Idaho, Nevada, New Mexico, Oregon, Utah, and Washington State) and estimated that there is up to 12,558 MW of recoverable geothermal power by 2025 from identified locations available at a future market at a cost of up to 20 cents per kilowatt-hour (¢/kWh). In the near-term, WGA estimated 5,588 MW of economically developable capacity (5.3–7.9¢/kWh (with the federal production tax credit (PTC) included) by 2015 in these 11 western states [120].

Europe

Simultaneously, in Europe, Bertani [123] in Bali, 2010 reported that Europe accounts for 1,635 MWe of installed geothermal capacity with growth forecasts to 2,125 MWe by 2015. Installation of new binary power stations will increase electricity production over a wide geographical distribution in locations fueled by medium-temperature resources including nonvolcanic sources in interior Eastern and Western Europe. Further, there will be greater development in Geothermal Heat Pump (GHP) installations that can be replicated around the world. As for direct use and GHP, John Lund reported at the Geothermal Resources Council Annual Meeting in October 2010 that European nations represent 10 out of the top 15 nations in utilization of these types of installations, with Sweden in third place behind China and the USA (focused mostly on GHP). Turkey is in fourth place focused mostly on district heating (Lund and Bertani [121]).

Geothermal Resources

Evaluation of the geothermal energy reserves was compiled for the MIT publication "The Future of Geothermal Energy" [122] according to the various types of geothermal systems:

(a) Hydrothermal convective systems
(b) Enhanced geothermal systems ("EGS")
(c) Conductive sedimentary systems
(d) Hot water produced from oil and gas fields
(e) Geopressured systems
(f) Magma bodies

Hydrothermal Convective Systems *Hydrothermal convective systems* to date have seen several decades of commercial exploitation for electric power generation in about 24 countries, but their distribution worldwide is limited. The installed power capacity for such systems totaled 10,715 MW worldwide by the end of the first decade of the twenty-first century, of which 3,000 MW were in the USA. The reserve base for these systems in the USA is estimated to be in the 10,000–30,000 MW range. Technologies involved for power generation from these sources are considered mature. Data sources are in WGC [123] and GEA [124].

Enhanced Geothermal System (EGS) An *enhanced geothermal system (EGS)* implies a man-made reservoir created by hydrofracturing impermeable or very "tight" rock through wells. The creation of an EGS system is performed by injecting water in an artificially fractured reservoir well with production from another well. By using rock heated water it is possible to extract thermal energy. EGS systems are conductive systems with enhanced flow and storage capacity due to hydro fracturing. In theory, EGS can be developed anywhere in the world by drilling deep enough to encounter commercially attractive rock temperatures. However, EGS technology is still experimental and poses a series of technical challenges, such as:

(a) Creating a pervasively fractured large rock volume
(b) Securing commercially attractive well productivity
(c) Minimizing the rate of cooling of the produced water with time
(d) Minimizing the loss of the injected water through fractures
(e) Minimizing any induced seismic effects

Sedimentary Systems Attempts are being made to develop geothermal *projects in sedimentary basins* with high heat flow (particularly in Australia). These systems are neither EGS or convective systems (due to the presence of impermeable shale layers preventing convection). No fracturing is generally needed for such systems as sedimentary rocks have intrinsic porosity and permeability. However, very deep wells are required to exploit such systems and ensure an adequate temperature level (well productivity may not prove adequate). No such systems have been commercially exploited to date. Developing such systems should be feasible if reservoir temperatures and flow capacities are sufficiently high.

Coproduction with Oil and Gas Wells Another geothermal energy resource presently being considered for exploitation is the heat contained in the water produced from *deep oil and gas wells*. Here the hot water may be coproduced with petroleum production, from existing or abandoned oil or gas wells. While there are no significant challenges to exploiting this energy resource, the cost of this power may not always be attractive due to the relatively low temperature and low production rate of the water.

"Geopressured" Systems "*Geopressured*" *systems* are very restricted geothermal energy resources. These systems are confined sedimentary reservoirs with pressures greatly higher than the local hydrostatic pressure. The high pressure in such systems may allow the exploitation of the kinetic energy of the water produced in addition to its thermal energy. Furthermore, due to the high pressure, such a system may contain attractive amounts of methane gas dissolved in the water which may be used to generate electric power in a gas engine. Therefore, an ideal geopressured well can provide thermal, kinetic and gas-derived energy. No commercial geopressured project has been developed to date and there are several technical challenges to making this energy source commercial.

Magma Bodies Exploitation of geothermal energy directly from a magma body is theoretically possible but faces many technical challenges.

The US reserves of the various geothermal systems discussed above are summarized in Table 1–1 of the MIT report [122].

Of the six basic types of geothermal energy in the USA, the potential from an EGS resource system is three orders of magnitude higher than the other types combined. For additional views see [125, 126]. This conclusion also applies for the rest of the globe.

US View to 2050

Although, as described above, hydrothermal resources retain significant potential, the potential is limited mostly to the Western USA with a smaller contribution possible from coproduced and geopressured systems from oil- and gas-producing states, such as the Gulf Coast. EGS represents a more widely distributed resource base, requiring substantial investment in R&D. An 18-member assessment panel assembled in September 2005 evaluated the technical and economic feasibility of EGS becoming a major supplier of primary energy for US baseload generation capacity by 2050. The MIT report was rediscussed in the DOE Workshop on June 7, 2007 [127], with an intention to recommend DOE action items.

The questions raised were:

1. What is the quality, grade, and distribution of the EGS resource nationally?
2. What is still to be done technically to achieve complete EGS system feasibility?
3. What are the key technical and economic issues that must be resolved for EGS to have national impact in US energy supply by 2050?

The primary goal was to provide an in-depth evaluation of EGS as a major primary energy supplier to the USA. The secondary goal was to provide a framework for informing policy makers of R&D support and policies needed for EGS to have a major impact.

Major impact was defined as enabling 100,000 MWe of an economically viable EGS resource online or as a true reserve by 2050.

Findings were:

1. Large, indigenous, accessible base load power resource – extractable amount of energy that could be recovered is not limited by resource size. EGS can sustain production of $\geq$100,000 MWe of base load electric power.
2. Fits portfolio of sustainable RE options – EGS complements the DOE's RE portfolio and does not hamper the growth of solar, biomass, and wind in their most appropriate domains.
3. Scalable and environmentally friendly –EGS stations have small foot prints and low carbon-free emissions. The stations are inherently modular making them easily scalable from 1+ to 50+ MWe size individual stations, grouping to large base load facilities >1,000 MWe.
4. Technically feasible – much progress in 30+ years of testing worldwide, the major elements of the technology to capture and extract EGS are already in place. Remaining key issue is to establish inter-well connectivity at commercial production rates – only a factor of 2–3 greater than current levels.
5. Economic projections – favorable for high grade areas now with a credible learning path to provide competitive energy from mid-and low-grade resources.
6. Deployment costs low – a modest investment of US$300–US$400 million over 15 years would demonstrate commercial scale EGS technology at several US field sites to reduce risks for private investment and enable the development of 100,000 MWe.
7. Supporting research costs are reasonable – in comparison to other large impact alternative energy programs supported by the US government.

The financial support recommends investing a total of US$600–US$800 million for deployment assistance, research and development over 15 years. This is an average of US$50 M/year.

Refer to the EERE website http://www1.eere.energy.gov/geothermal/ [128] for a follow-up of the DOE Geothermal Technologies Program.

Europe View to 2050

At the Offenburg conference, 2009, Bertani [129], who based his observations largely on Fridleifsson et al. [130], saw a linear increase in direct use of geothermal resources for space heating, greenhouses, etc. Simultaneously the increase of GHP including power

generation grew exponentially from about 200,000 TJ/year expected in 2010 to 900,000 TJ/year expected in 2020 to above 4 × 106 TJ/year in 2050. For comparison, the world energy consumption is presently about 420 EJ/year. (1 EJ = 1,018 J, 1 TJ = 1,012 J).

Following the US evaluation, a committee of the Council of Europe met to handle the issue – Geothermal Energy: a solution for the future? A motion for a resolution is found in Doc: 11740 [131].

Presented European and world information proposed that the assembly should focus on geothermal energy and its potential contribution to clean and sustainable energy systems in Europe.

A more in-depth survey followed and was discussed by the Council of Europe in May 2010 as reported in Doc. 12249 [132]. A report of European and world geothermal data was presented at the meeting and summarized in Doc. 12249. The report handles technical data while also noting connected hurdles, technical barriers and seismic problems. Examples of such occurrences were given including Landau, Staufen-im-Brisgau in Germany and a Soultz-type geothermal project launched on a commercial basis in Basel, Switzerland in 2006. This project ceased drilling after the inhabitants reported mini earthquakes around the project site.

The draft resolution detailed the data, stressed the advantages of geothermal energy in urban heating, electric generation and positive impact on the environment. Legislative issues and financial risks were also covered. Resolution No. 9 or the "to-do" recommendations are listed below (from the original):

9.1 Foster the development of geothermal energy operations in their national energy strategies.
9.2 Encourage the use of geothermal energy in all its forms, particularly locally.
9.3 Encourage international cooperation in the transfer of technology and the financing of geothermal development.
9.4 Increase realization and awareness among the general public and potential investors of the advantages of geothermal technologies for a sustainable energy infrastructure.
9.5 Take the necessary steps to set up strategic research programs and encourage the exploitation of geothermal energy resources.
9.6 Foster the introduction of financing and insurance schemes for exploration.
9.7 Encourage the setting up of transfrontier cooperation schemes to finance surface measurements and test drillings.
9.8 Introduce a European training and professional development framework.
9.9 Draw up a map of geothermal energy resources at the European level within the framework of cooperation between the geological research bodies of each country.

For additional information on European data on future plan and research go to [133]. The future of geothermal development European Geothermal Energy Council (EGEC) Projections www.egec.org, 2010 and [134] European Commission Research – Future prospects, hurdles: http://ec.europa.eu/research/energy/eu/research/geothermal/background/index_en.htm

Global View

Renewable energy including geothermal energy plays an important role in future global policies. In his book, Plan B 4.0 "Mobilization to save the Earth," Brown [135] accounted for the existing and potential geothermal resources in the section on "Choosing the Energy Conversion Systems," which deals with renewable energy. Besides the energy use for power production he details direct usage for domestic heating, heat pumps for heating and cooling. In Germany alone he reports there are 130,000 operating heat pumps with 25,000 being added annually. Leaders for direct use of the above include:

- District heating: Iceland, Hungary, France, and China.
- Pools and spas in Iceland, France, and Japan.
- Greenhouses in Russia, Hungary, Iceland, and USA.
- Aquaculture in China, Israel, and the USA.

The previously mentioned GEA report 2010 [124] summarizes the existing portfolio of power stations and gives a prospect for increase until 2015. Highlights are:

According to the International Geothermal Association in 2005, there was 8,933 MW of installed power capacity in 24 countries, generating 55,709 GWh of green power per year. IGA reports in 2010 that there is 10,715 MW online generating 67,246 GWh. This

represents a 20% increase in online geothermal power between 2005 and 2010. IGA projects this will grow to 18,500 MW by 2015, as based on the large number of projects under consideration (Bertani [123]).

Countries which experienced significant increases in installed capacity between 2005 and 2010 included the USA, Indonesia, Iceland, New Zealand and Turkey. These nations expect to have a significant increase by 2015. However, other nations expect to increase generation significantly during that time including Kenya, Russia, the Central American nations of El Salvador, Guatemala, Nicaragua and the South American nation of Chile, which currently has 0 MW of installed capacity (Bertani [123]).

While on-line power increased 20% between 2005 and 2010, countries with projects under development grew at a much faster pace. GEA reported in 2007 that 46 countries were considering geothermal power development. In 2010, an updated report acknowledged 70 countries with projects under development or active consideration, a 52% increase since 2007 (GEA [124]).

Projects under development grew most dramatically in two regions of the world, Europe and Africa. Ten countries in Europe were listed as having geothermal projects under development in 2007, and this has more than doubled in 2010 to 24 countries. Six countries in Africa were identified in 2007 and in 2010, 11 were found to be actively considering geothermal power. It would appear that bodies such as ARGeo and the European Bank for Reconstruction and Development's geothermal initiatives are having a considerable beneficial effect.

However, despite these growth trends, potential of geothermal resources to provide clean energy appears to be underestimated. In 1999, GEA prepared a report that examined geothermal power potential internationally. The report showed that in the vast majority of countries the estimated potential remains undeveloped and largely untapped, even assuming the lowest projections for geothermal resource potential. Moreover, the number of countries with geothermal power potential still not developing their resources is still high. Of the 39 countries identified in 1999 as having the potential to meet 100% of their electricity needs through domestic geothermal resources, significant power production had been developed in only nine – Costa Rica, El Salvador, Guatemala, Iceland, Indonesia, Kenya, Nicaragua, Papua New Guinea and the Philippines. However, this report identified projects under consideration in another 14 of these countries. (For a list of countries identified in the 1999 GEA report which could be 100% geothermal powered, see the Appendix in [124].)

The underlying trend of geothermal power expansion is complemented by the development of projects in entirely new areas. It is interesting to note that there are 24 countries identified with geothermal power projects under development not included in the GEA 1999 study. Most of these countries are in Europe and are accessing resources with new technology developments that allow development of lower-temperature resources. In addition, EGS technologies, or enhanced geothermal systems, are being developed in a number of countries including Australia, France, Germany, the UK and the USA.

The trends in both the number of new countries developing geothermal energy and the total of new megawatts of power capacity under development appear to continue a growth trend showing a clear reverse from the slowdowns in international markets as seen in the late 1990s. Supported by the development of low-temperature power on the one side and EGS technologies on the other side, the geothermal market appears to be expanding to encompass most of the world's potential geothermal sites.

The report indicates that national and international policies, as well as financial support, are key in realizing the potential for successful geothermal development.

Additional GEA Observations:

- In 2010, global geothermal development is partly being driven by a number of regional institutions which, in addition to financing geothermal projects, are enhancing regional cooperation within an emerging renewable energy sector. Examples include the African Rift Geothermal Energy Development Facility (ARGeo), which underwrites drilling risks in six African nations and is backed by UNEP, the World Bank, and the geothermal initiatives of the European Bank for Reconstruction and Development supported by European Union climate policies.
- Geothermal development appears to be increasingly supported by a global financial market. A growing number of countries, including Australia, China, Germany, Iceland, Italy, Japan, and the USA, are facilitating geothermal development projects around the

world. Forms of support other than financing, including technology sharing, training, and geological surveys are also being endorsed by outside governments.

- The growth in geothermal projects under consideration or in development is in part attributable to international and multilateral support for development in new areas. The ongoing question is whether that support will be sustained over time and be adequate to address risks involved in geothermal project development. For example, geothermal resources are abundant in East Africa and support for resource assessment has helped spur interest in project development in several countries. But, new projects will have high associated costs and risk factors. Sustained support for development at this crucial stage is essential to achieving expanded use of geothermal energy in this and other developing areas.
- Geothermal development appears to be trending beyond traditional hydrothermal reserves prevalent along the Pacific Ring of Fire. Lower temperature power systems and EGS technology are allowing a growing and diversified collection of countries to actively pursue geothermal development in areas previously assumed to have little exploitable resource. This is especially true among European countries, notably France, Germany, Latvia, and the UK, all of which are currently exploring and developing local resources by employing EGS. These developments are supported by government policies (such as feed-in tariffs), which make higher-risk and higher-cost projects more feasible. These policies are typically components of broader climate initiatives.
- District heating and direct use of geothermal applications appear to be progressively more commonplace in many countries and are being emphasized in a number of national renewable energy policies as effective measures for curbing greenhouse gas emissions.
- Around the world, villages and tribes are looking to geothermal as a way to utilize land and become energy independent. Warm Springs Indian Reservation in Oregon, the Northwestern Band of Shoshone Nation in Idaho and Utah, and the Jemez Pueblo in New Mexico have all shown interest in developing geothermal energy. Additionally, the Pyramid Lake Paiute Tribe in Nevada is actively developing its geothermal resources and was recently awarded funding from the US DOE. In New Zealand, the Te Arawa Iwi is examining the possibility of geothermal power on Maori land in Rotorua. In The Philippines, 9 of 11 ancestral domain areas consented to the Kalinga geothermal exploration project. A geothermal station is expected to open in the small settlement of Innamincka, Australia, in early 2012.

A country-by-country assessment (both present and forecasted for 2015) is summarized in the WGC report by Bertani [123] and in the GEA report [124] which is arranged by continents considering natural geothermal data and national policies.

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Geothermal Power Economics

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Article Outline

Glossary

Capital cost Capital costs are the one-time costs incurred on project acquisition, drilling, construction, and equipment needed to bring a project to a commercially operable status.

Levelized power cost The present value of the total cost of developing and operating a geothermal power plant over its economic life divided by the total power generated over the same period, costs being levelized in real dollars (i.e., adjusted to remove the impact of inflation).

Make-up well cost Cost of drilling "make-up" wells as needed during project operation.

Operations and maintenance (O&M) Cost Those expenses used for the day-to-day operation of a power facility. The major categories include personnel, general and administrative, insurance, supplies and services, well maintenance, and equipment maintenance costs.

Power capacity The maximum output of power from a power plant, commonly expressed in megawatts (MW).

Definition of the Subject and Its Importance

Geothermal power is the rate of extraction of geothermal energy, whether expressed as heat energy or equivalent electrical energy, and is expressed as Watt or an equivalent unit. The extraction of geothermal energy, and therefore geothermal power capacity, is dependent not only on the technological barriers to this energy extraction but also on the economic barriers. Power generation from geothermal energy, therefore, requires consideration of the economics of geothermal power. This entry considers power cost as the main economic criterion rather than the power price or project profitability because, unlike price or profitability, cost is substantially independent of the corporate culture of the developer and operator, financing mechanism, local market forces, and government policies. The most comprehensive measure of the geothermal power cost is "levelized" power cost, expressed typically as cents per kW-hour power generated over the life of a power plant.

Introduction

The power cost considered here is "levelized" cost (¢/kWh) over the project life, defined here as the cumulative present value of all future costs including annual payments for amortized capital in real dollars (adjusted for inflation) divided by the cumulative power generated [1]. The initial capital cost is amortized over a period of 30 years; make-up well drilling cost is not capitalized and is considered an operating expense. The capital cost includes the cost of money (i.e., the cumulative future interest payments discounted for inflation) but does not include any transmission line cost or any unusually site-specific costs of regulatory compliance or environmental impact mitigation.

Cost calculations in this entry ignore any royalty burden, tax liability, or tax credit. The values of economic parameters assumed in this entry reflect the setting in the USA as of year 2005. However, levelized cost of geothermal power has approximately doubled between 2005 and 2010 because of large increases in drilling cost and commodity prices. Even so, the conclusions arrived at should still be applicable at least qualitatively to geothermal power projects worldwide. In the debate over the relative virtues of various forms of renewable energy, power cost is an objective criterion that should favor geothermal; yet there is considerable difference of opinion as to what it truly is and can be.

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The analysis, extracted from Ref. [1], considers a power capacity range of 5–150 MW with 50 MW as the "base case." Power cost consist of three components: (1) capital cost component (including cost of money), (2) operations and maintenance (O&M) cost component (not counting debt service, which is included under the capital cost component), and (3) make-up well drilling cost component.

Factors That Determine Geothermal Power Cost

These factors can be grouped into four categories: (1) economy of scale, (2) well productivity characteristics, (3) development and operational options, and (4) macroeconomic climate. In general, economy of scale allows both unit capital cost (in US dollars per kilowatts installed) and unit O&M cost (in ¢/kWh) to decline with increasing installed capacity. Based on the data presented by Entingh and McVeigh [2], the unit capital cost (as of 2005) is estimated to vary from $1,600/kW to $2,500/kW depending on project size and other project-specific criteria. For the smallest project size of 5 MW considered here, the author has assumed a unit capital cost of $2,500/kW and for the largest considered project size of 150 MW a cost of $1,600/kW. A permissive assumption has been made that within the above range of values, unit capital cost declines exponentially with plant capacity. This assumption leads to the following correlation between unit capital cost in $/kW ($c_d$) and plant capacity in kW (P):

$$c_d = 2500e^{-0.003\,(P-5)} \tag{1}$$

For the 50 MW base case, the unit capital cost is estimated from Eq. 1 at $2,184/kW. GeothermEx's experience shows the representative unit O&M cost approximately ranged from 2.0 ¢/kWh for a 5 MW plant to 1.4 ¢/kWh for a 150 MW plant in 2005. Assuming an exponential decline in unit O&M cost in ¢/kWh (c_o) with plant capacity in kW (P):

$$c_o = 2.0e^{-0.0025(P-5)} \tag{2}$$

For the 50 MW base case, the unit O&M cost is estimated from Eq. 2 at 1.79 ¢/kWh.

Well productivity characteristics affect geothermal power cost in mainly two ways:

1. If well productivity is higher, fewer wells are needed to supply a plant, thus reducing power cost.
2. A higher rate of decline in well productivity with time calls for more make-up well drilling, and therefore, leads to higher power cost.

For the purposes of this entry, an average initial productivity of 5 MW per well was assumed; this is a typical value. Geothermal wells generally undergo "harmonic" decline in well productivity with time [3]:

$$W = \frac{W_i}{1 + D_i t} \tag{3}$$

where W_i is initial productivity, D_i is initial annual decline rate in productivity, and W is productivity in year t. The harmonic decline trend implies a decline rate that slows down with time, the annual decline rate (D) in productivity in year t being given by [3]:

$$D = \frac{D_i}{1 + D_i t} \tag{4}$$

If the total production rate from a field is small enough to be entirely compensated by natural recharge or if only a small fraction of the productive reservoir is being exploited, the decline rate in well productivity would be insensitive to increases in plant capacity. These situations are much less common. In most cases, decline rate increases with increasing installed capacity. This sensitivity of productivity decline to installed capacity is too site-specific to be quantified by a generally applicable correlation. Nevertheless, Sanyal et al. [4] attempted an approximate formulation:

$$D_i' = \left(\frac{W_i'}{W_i}\right)\left(\frac{\ln W_i'}{\ln W_i}\right) D_i, \tag{5}$$

where D_i is initial annual harmonic decline rate when total production rate is W_i and D_i' is initial annual harmonic decline rate when total production rate is changed to W_i'. Assuming a typical initial harmonic decline rate of 5% per year for the 50 MW base case, the initial annual harmonic decline rate for any other plant capacity was estimated from Eq. 5.

There are certain resource development and operational options that affect power cost. The developer of a geothermal project has the option to size the power plant while the operator of the project has the option either to allow generation to decline with time or to maintain generation by make-up well drilling; the operator can also run the plant beyond its amortized life. The sensitivity of power cost to these intertwined options has been studied in this entry. The resource development option has been considered by varying the plant capacity within the range of 5–150 MW. The operational option has been considered by assuming make-up well drilling for various periods of time following plant start-up, and scenarios of plant operation both up to and beyond the amortization period.

While the unit capital cost for a given plant capacity, as given by Eq. 1, includes initial drilling cost, the unit O&M cost given by Eq. 2 does not include make-up well drilling cost. In order to estimate the make-up well drilling cost as a function of time, it is necessary to estimate first the initial number of wells required for a given plant capacity. This estimate was based on a typical initial productivity of 5 MW per well plus the customary need for at least one standby well and a minimum of 10% reserve production capacity at all times. With the above assumptions, it follows that the installed plant capacity can be maintained without any make-up well drilling for up to t_c years following plant start-up, as given by:

$$t_c = \frac{1}{D_i}\left[\frac{W_i N_{wi}}{(1 + r/100)P} - 1\right], \tag{6}$$

where D_i is initial annual harmonic decline rate, W_i is initial productivity per well (MW), N_{wi} is initial number of wells (including at least one standby well), P is plant capacity (MW), and r is minimum production capacity reserve required (%).

Estimating Levelized Power Cost

Figure 1 shows the schematic generation and make-up well drilling histories of a typical power project. Generation can be maintained without make-up well drilling up to year t_c, as given by Eq. 6. Then generation is maintained by make-up well drilling up to year t_d in response to decline in well productivity according to Eq. 3, the initial annual harmonic decline rate being given by Eq. 5. After year t_d, no make-up well is drilled and generation is allowed to decline as per Eqs. 3 and 5.

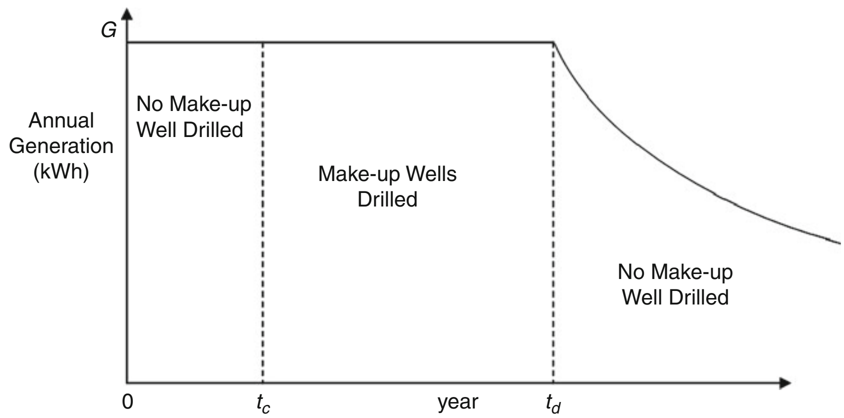
Given the generation and make-up well drilling histories represented in Fig. 1, the levelized cost of geothermal power ($\bar{c}$) in ¢/kWh is given by [1]:

$$\begin{aligned}\bar{c} = {} & \frac{100D(t_d)}{G\{D(t_d)t_d + \ln[1 + D(t_d)(n - t_d)]\}} \\ & \cdot \left\{\frac{iC(1+i)^n}{(1+i)^n - 1}\right\}\left\{\frac{(1+I)^n - 1}{I(1+I)^{n-1}}\right\} + c_{ov} + \left(\frac{t_d}{n}\right)c_{ofi}, \\ & + \frac{c_{ofi}}{n}\left\{(n - t_d) + \frac{D(t_d)}{2}(n - t_d)^2\right\} \\ & + \frac{100C_{wi}N_{wi}D(t_d)D(t_c)(t_d - t_c)}{G\{D(t_d)t_d + \ln[1 + D(t_d)(n - t_d)]\}}\end{aligned} \tag{7}$$

where $D(t)$ is annual productivity decline rate in year t; G is initial annual generation (kWh); N is power plant life (assumed to be 30 years in base case); C is total capital cost, that is, $c_d \cdot P$ ($); c_o is unit annual O&M cost (¢/kWh); i is annual interest rate (assumed to be 7% in base case); I is annual inflation rate (assumed to be 3% in base case); c_{ofi} is fixed portion of the annual O&M cost at plant start-up divided by initial annual generation (¢/kWh); c_{ov} is variable portion of the annual O&M cost divided by annual generation (¢/kWh); N_{wi} is number of initial production wells; and C_{wi} is drilling cost per initial production well (assumed to be $2 million in the base case).

Capital cost includes exploration cost, power plant cost, gathering and injection system cost, and cost of capital. Annual O&M cost includes personnel cost, general and administrative cost, insurance cost, supplies/consumables/engineering and laboratory services cost, wellfield maintenance cost, generator and turbine maintenance cost, and other equipment and maintenance cost.

The variable portion of the annual O&M cost represents costs that vary with the level of generation, such as, costs of supplies, consumables, etc.,



Geothermal Power Economics. Figure 1
Schematic generation and make-up well drilling histories of a project [1]

which remain proportional to generation; this cost divided by annual generation gives c_{ov}. The fixed portion of the annual O&M cost represents costs that are independent of the generation level; these include costs of personnel, administration, insurance, wellfield maintenance, generator and turbine maintenance, other equipment maintenance, etc., which may not decline in response to any decline in generation. This fixed annual cost divided by annual generation gives c_{of}. For the purposes of this entry, 20% of the annual O&M cost was assumed to vary with generation at plant start-up; however, results are found to be relatively insensitive to the fraction of O&M cost that is variable. As generation declines, c_{ov} remains constant but c_{of} increases from its initial value of c_{ofi}. A typical plant capacity factor of 90% was assumed in estimating annual generation. In Eq. 7, the total capital cost (C) is assumed to be amortized over the plant life of n years at an interest rate i (annual compounding). The calculated power costs in future years are discounted for inflation to arrive at a levelized power cost in present dollars ($\bar{c}$).

Sensitivity of Levelized Power Cost

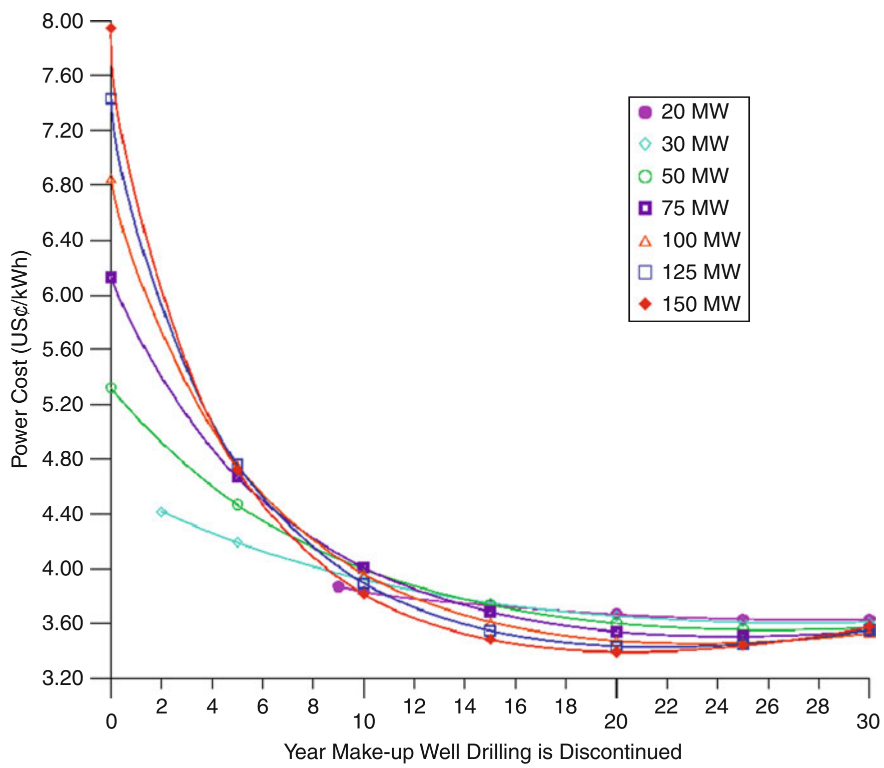
It should be noted that if there were no economy of scale in capital and O&M costs (i.e., a capital cost of $2,184/kW and an O&M cost of 1.79 ¢/kWh, as in the base case) and if productivity decline rate were insensitive to installed capacity (remaining at 5% initial annual harmonic rate as in the base case), levelized power cost from Eq. 7 would be 3.6 ¢/kWh irrespective of plant capacity. Table 1 lists all parameters for the range of development scenarios analyzed, assuming the economy of scale in capital and O&M costs as well as the sensitivity of productivity decline to plant capacity.

Figure 2 shows the calculated power cost in ¢/kWh for various levels of installed plant capacity as a function of t_d (i.e., the number of years of make-up well drilling undertaken to maintain plant capacity). This figure takes into account the economy of scale as reflected in Eqs. 1 and 2, as well as acceleration in well productivity decline, as given by Eq. 5, with increased installed capacity. Figure 2 indicates that power cost declines with the number of years of make-up well drilling, the decline rate being steeper for a higher plant capacity. Figure 2 also indicates that if make-up well drilling is discontinued too early (prior to about 10 years), power cost would be higher for a larger plant. This figure also shows that for any plant capacity, a relatively minor reduction in power cost is achieved by continuing make-up well drilling after this period, and continuing make-up well drilling beyond about 20 years may actually increase power cost. Therefore, there is little reason to continue make-up well drilling beyond about 20 years unless the power sales contract imposes significant penalties for any shortfall in plant capacity.

Geothermal Power Economics. Table 1 Development scenarios analyzed

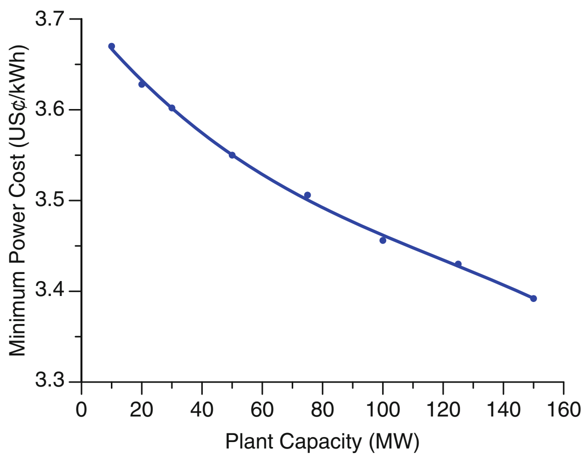
Plant capacity (MW)[c]	Capital cost per kW	Total capital cost (million $)	O&M cost (¢/kWh)[b]	Initial harmonic decline rate (%)	No. of initial production wells[a]	Years before make-up well drilling is required (t_c)
5	2,500	12.5	2.0	0.2	2	>30
10	2,463	24.6	1.98	0.6	3	>30
20	2,390	47.8	1.93	1.5	5	9
30	2,319	69.6	1.88	2.6	7	2
50	2,184	109.2	1.79	5.0	11	0
75	2,025	152.0	1.68	8.3	17	0
100	1,880	188.0	1.58	11.8	22	0
125	1,744	218.0	1.48	15.4	28	0
150	1,618	242.7	1.39	19.2	33	0

[a]5 MW per well/minimum of one standby well/minimum of 10% excess capacity
[b]80% of O&M cost varies with capacity
[c]Plant capacity factor=0.9

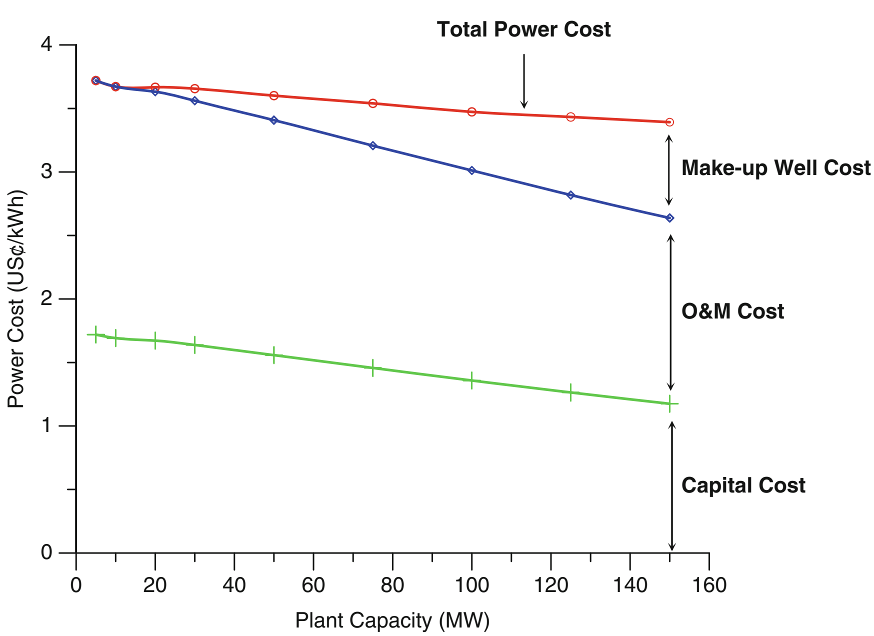


Geothermal Power Economics. Figure 2
Levelized power cost versus the year make-up well drilling is discontinued [1]

Figure 3 shows the minimum achievable power cost for various plant capacities as read from Fig. 2. This figure shows that the minimum achievable power cost is rather insensitive to plant capacity; it varies from 3.7 ¢/kWh for a 10 MW plant to 3.4 ¢/kWh for a 150 MW plant, a 7.6% decline in power cost for a 1,400% increase in power capacity. Irrespective of the plant capacity and the number of years of make-up well drilling, power cost as of 2005 could not be lowered significantly below 3.4 ¢/kWh. Figure 4 shows the three components of power cost (capital, O&M, and make-up well drilling) as functions of plant capacity assuming make-up well drilling to be discontinued after 20 years. This figure shows that the capital cost component is approximately equal to the O&M cost component for all plant capacities while the make-up well drilling component assumes greater significance with increasing plant capacity (except for very small capacities). Furthermore, the sum of O&M and make-up well drilling components constitutes the major part of power cost. Capital expenditure is incurred in the first few years of a project, when site-specific knowledge of the resource is still limited; therefore, adequate optimization of capital investment can be a challenge. After plant start-up, little can be done to reduce the capital cost component of power cost, except perhaps refinancing the debt should the interest rate decline. On the other hand, O&M and make-up well drilling costs, being incurred gradually as production continues, should reduce with time due to the "learning



Geothermal Power Economics. Figure 3
Minimum levelized power cost versus plant capacity [1]

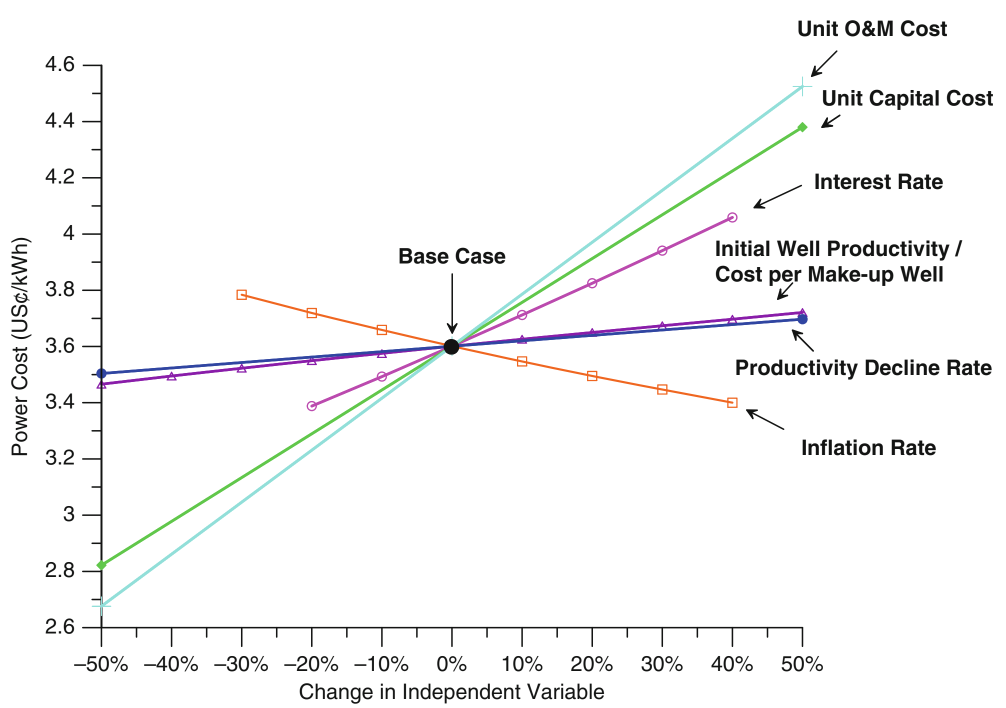


Geothermal Power Economics. Figure 4
Components of levelized power cost versus plant capacity (assuming 20 years of make-up well drilling) [1]

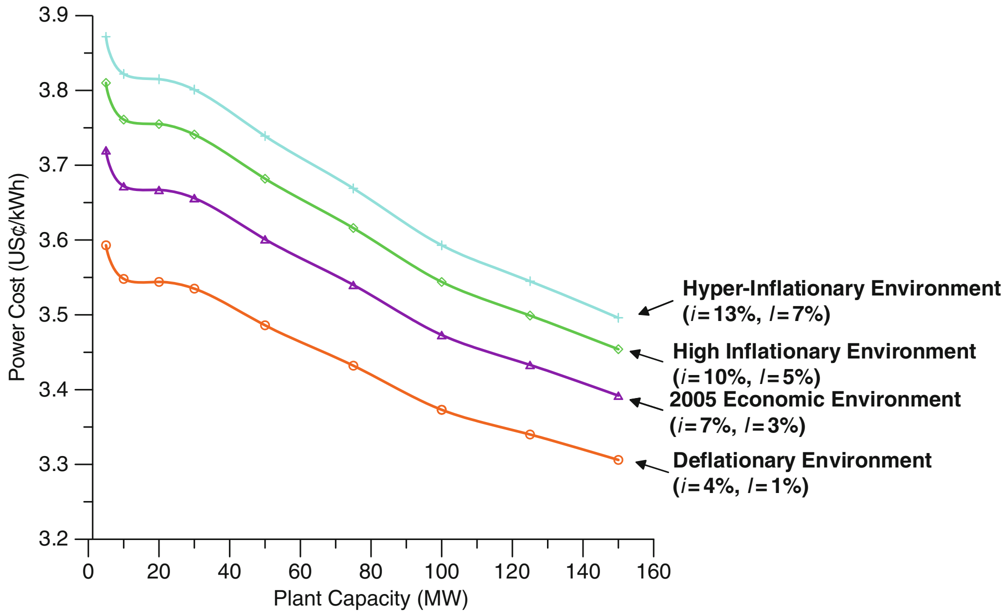
curve" effect. As more understanding of the resource characteristics and reservoir performance is gained with operation, O&M and make-up well drilling costs can be reduced, lowering power cost.

Figure 5 is a plot of power cost versus percent deviation in the values of the various independent variables from their base case (50 MW) values. In this figure, a steeper curve through the base case point implies a higher sensitivity of power cost to the variable represented by the curve. Figure 5 shows that unit O&M cost and unit capital cost have the highest impact on power cost; these two variables are also subject to economy of scale. On the other hand, power cost is relatively insensitive to resource-related variables (such as well productivity, drilling cost per well, and productivity decline rate). Figure 5 indicates a levelized power cost of 3.6 ¢/kWh as of 2005 for a 50 MW plant. However, it should be noted that the author's experience as of 2005 indicated that the estimates of capital cost in the USA as of 2005 based on Ref. [2] was somewhat low. For the base case, the capital cost in the USA as of 2005 was as much as 30% higher than $2,184/kW. Therefore, Figure 5 shows that the levelized power cost for a 50 MW plant in the USA as of 2005 was as high as 4.1 ¢/kWh; in 2010 it is as high as 8 ¢/kWh.

Interestingly, power cost is only modestly sensitive to macroeconomic variables (interest and inflation rates), because interest and inflation rates affect power cost by about the same magnitude but in opposite directions (Fig. 5). Figure 6 shows power cost versus plant capacity for several diverse microeconomic situations: (1) a hyperinflationary environment, (2) a high inflationary environment, (3) the economic environment in the USA as of 2005, and (4) a deflationary environment; appropriate interest rates (i) and inflation rates (I) assumed for the various cases are shown on the figure. Figure 6 implies that, in relative terms, the



Geothermal Power Economics. Figure 5
Sensitivity of base case power cost to changes in independent variables [1]



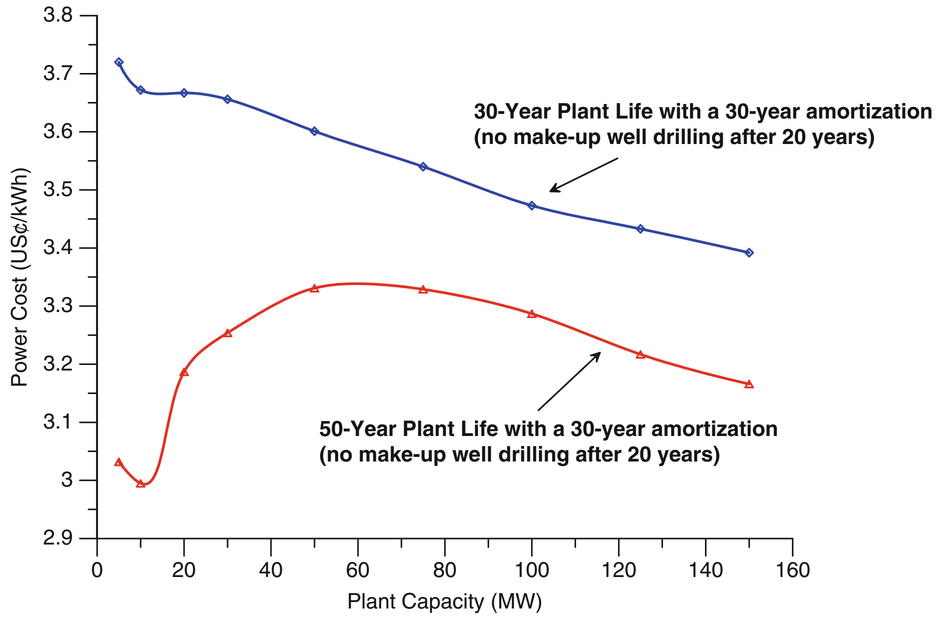
Geothermal Power Economics. Figure 6

Levelized power cost versus plant capacity under various macroeconomic conditions (for 20 years of make-up well drilling) [1]

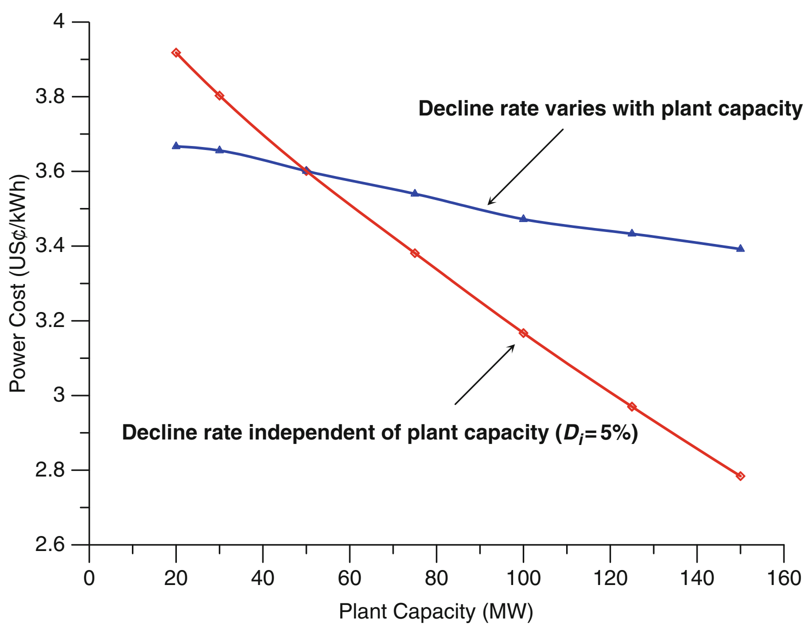
sensitivity of power cost to the macroeconomic climate is not significant. For example, the variation in power cost over the capacity range of 5–150 MW is of similar magnitude as the variation in power cost in the base case over the extreme range of macroeconomic climates considered.

History of operation of geothermal power plants in Italy, New Zealand, El Salvador, Mexico, Japan, and USA, where some plants have already operated for more than 30 years, indicates that it is possible to continue operating a geothermal plant beyond its typical amortization period of 20–30 years. Can power cost be reduced if a geothermal plant were amortized for 30 years but operated for a longer period? Figure 7 compares power cost versus plant capacity as shown before (for 30 years' operation) and as calculated for a 50-year operating period, the initial capital cost still being amortized over 30 years. Figure 7 shows that for smaller plants, cost may be reduced significantly, by as much as 20% for plants of 10 MW or smaller capacity. For plants larger than about 50 MW, this reduction in power cost is not significant, particularly considering the additional risk of operating an aging power plant and pipelines, and possibly deteriorating wells.

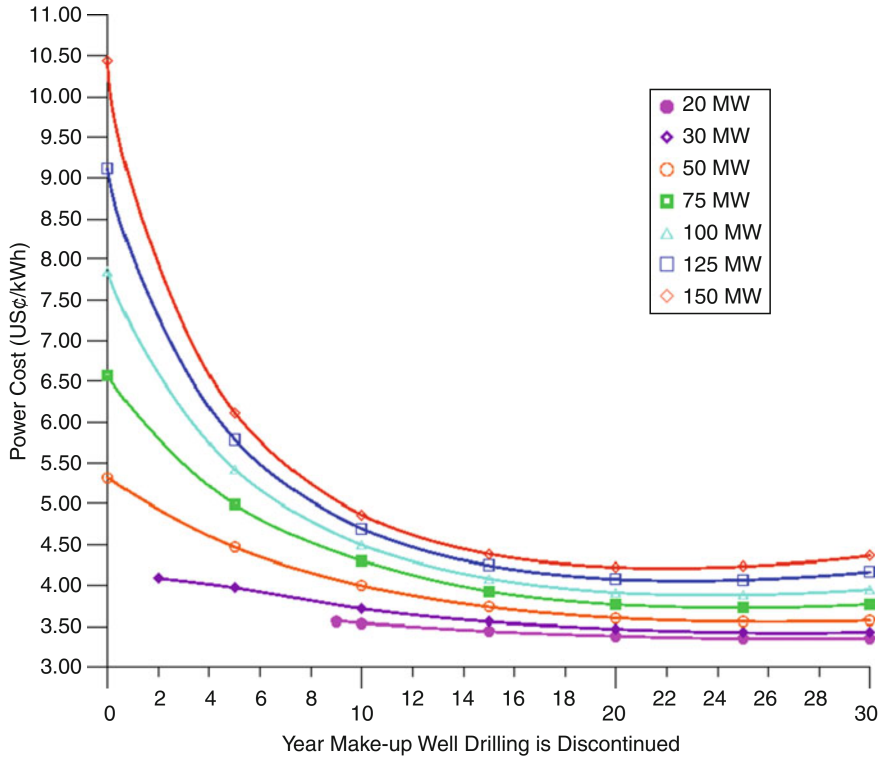
The above analysis takes into account the usual acceleration in well productivity decline due to increases in plant capacity. How would the results change in the unusual case of well productivity being insensitive to installed plant capacity? Figure 8 compares levelized power cost as a function of plant capacity, as calculated before, with the case of a constant initial annual harmonic decline rate of 5% irrespective of capacity. Figure 8 shows that if productivity decline rate were insensitive to plant capacity, power cost would decline with plant capacity much more rapidly than in the usual case, the minimum power cost being only 2.8 ¢/kWh (for a 150 MW plant). However, a stand-alone project of a capacity larger than 100 MW is a rarity in the geothermal industry. The existing fields with a generation level greater than 100 MW typically rely on multiple, independent units of up to 100 MW each; as such, the economy of scale enjoyed by these projects would amount to that for a capacity of 100 MW or less.



Geothermal Power Economics. Figure 7
Effect of plant life on levelized power cost (20 years of make-up well drilling) [1]



Geothermal Power Economics. Figure 8
Levelized power cost versus plant capacity (for 20 years of make-up well drilling) [1]



Geothermal Power Economics. Figure 9
Levelized power cost versus the year make-up well drilling is discontinued ("no economy of scale" case) [1]

Therefore, if well productivity were insensitive to plant capacity, a power cost of less than 3.2 ¢/kWh (estimated for a 100 MW plant) as of 2005 was unlikely to be realized.

Finally, how would the results change if economy of scale in capital and O&M costs were negligible? One such conceivable situation could be the installation of multiple, modular and infrastructurally independent power plants in the same field. Figure 9 presents power cost versus the number of years of make-up well drilling for various plant capacities ignoring economy of scale. The results in this figure assume that unit capital and O&M costs remain the same as in the base case irrespective of installed capacity, but productivity decline still increases with installed capacity as given by Eq. 5. Figure 9 indicates that if economy of scale were negligible, power price would increase with installed capacity no matter how long one continues make-up well drilling, and power price would be consistently higher than in the usual case with economy of scale. The minimum achievable power cost in this case is still on the order of 3.4 ¢/kWh as of 2005 (estimated for a 20 MW plant).

Concluding Remarks

1. Power cost is sharply reduced by maintaining full generation capacity, by drilling make-up wells, for at least the first 10 years or so following plant start-up; continuing make-up well drilling beyond 20 years does not reduce power cost significantly.
2. The minimum achievable power cost is insensitive to plant capacity; as of year 2005, it was on the order of 3.4 ¢/kWh. There are significant opportunities to reduce power cost as site-specific experience is gained in resource management and power plant operation throughout the project life.

3. The levelized cost of power from a 50 MW plant as of 2005 was in the range of 3.6–4.1 ¢/kWh; it is approximately twice as of 2010.
4. Power cost is most sensitive to unit O&M cost followed by unit capital cost, interest rate, and inflation rate in the decreasing order of sensitivity; it is relatively insensitive to well productivity, drilling cost per well, well productivity decline rate, and the macroeconomic climate.
5. Operating small power plants (10 MW or less capacity) beyond their typical amortization period of 30 years can significantly reduce power cost.
6. The minimum achievable power cost does not decline significantly with increasing plant capacity except in the unlikely situation of well productivity decline being insensitive to capacity, when it was as low as 3.2 ¢/kWh as of 2005. In the unusual situation of an absence of economy of scale, power cost increases with plant capacity, the minimum achievable level being 3.4 ¢/kWh. In the very unlikely situation of both well productivity decline as well as unit capital and O&M costs being insensitive to plant capacity, the minimum achievable power cost would be on the order of 3.6 ¢/kWh in 2005 dollars.

Future Directions

This entry analyzes the levelized cost of geothermal power as of 2005. Between 2005 and 2010, this cost has escalated in spurts; today levelized cost is nearly double that in 2005. However, at this time the cost escalation is relatively slow.

While levelized cost of geothermal power has increased over the last 5 years, so has the price available for geothermal power in the USA by a similar ratio. The recent price increases have been driven by a host of new incentives for geothermal power introduced in the USA: (1) the Renewable Portfolio Standard ("RPS"), which requires an utility to derive a minimum fraction (0–33% depending on the State) of its power from renewable resources; (2) a Production Tax Credit ("PTC") of about 2 ¢/kWh for geothermal power; (3) the option to receive an Investment Tax Credit (30% of the capital investment) at the onset of power generation in lieu of PTC; (4) a renewable energy credit ("REC") in the USA or carbon credit worldwide; Geothermal Loan Guaranty, etc. Therefore, it is reasonable to expect that the price of geothermal power will continue to keep pace with, or most likely increase relative to, levelized cost of geothermal power for the near future.

It should be noted that this entry considers the economics of power from conventional geothermal systems, which are naturally occurring subsurface porous or fractured systems that can be tapped for production by drilling wells. However, in the last decade, considerable hopes have been raised of tapping geothermal energy from enhanced geothermal systems ("EGS") [5]. These are hot subsurface systems with porosity or fracture capacity too low to allow commercial production but can be enhanced by pervasive hydraulic fracturing to enable significant fluid injection and production. In an EGS project, heat is recovered from the artificial reservoir by injecting cool water through a set of wells while producing heated water from another set of wells. Such systems have not yet proven commercial, but research and development toward commercial tapping of EGS systems continue. Even in countries where conventional geothermal systems do not exist, EGS developments would be the theoretically possible, because anywhere on earth adequately hot rock bodies can be reached by drilling wells deep enough and creating an artificial reservoir by hydraulic fracturing of rock. Sanyal et al. [6] has presented an analysis of the economics of a prototype EGS project. However, until EGS power proves commercial, its economics would have significant uncertainties.

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Geothermal Power Stations, Introduction to

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Geothermal energy, contrary to solar and wind, does not depend on weather and is the only one which can supply base-load power. Although not evenly distributed geographically, geothermal energy potential is very important, particularly if the R&D of such advanced systems will be actively pursued.

This section covers the nature of geothermal energy resources, their utilization, conversion technologies as well as its future development (► Geothermal Energy, Nature, Use, and Expectations). The section also highlights the greatest challenge in geothermal development, namely, the geothermal resource. Power conversion is the least uncertain part of a geothermal project, as it consists of a straightforward engineering design with work executed by experienced manufacturers, engineering firms, and contractors.

The risks and challenges are related to exploration, drilling, and managing the resource. Optimization depends on the choice of adaptation of the power station configuration to the resources available.

When considering different types of resources and uses of geothermal energy, it is important to differentiate between geothermal or ground source heat pumps (GSHP) which utilize the natural insulation of the Earth for heating and cooling, as compared to hydrothermal resources, which are natural flows of geothermal-heated waters associated with underground heat sources or hot rocks.

- The comparative advantages of geothermal energy use include low emissions, high capacity factors, sustainability, and minimal land footprints.
- Hydrothermal sources can be utilized directly for space heating and other direct uses. This source can also be used for power generation if fluids of sufficient temperatures are available at commercial depths.

The distribution of geothermal resources is irregular due to unequal distribution of volcanoes, hot springs, and heat manifestations at specific locations over the Earth's surface (► Geothermal Energy, Geology and Hydrology of). Geothermal resources are a reflection of the underlying global, local geological and hydrological framework. The most thermally rich resources tend to concentrate in environments with abundant volcanic activity and tend to be controlled by plate tectonic processes or spreading centers evident as, volcanic chains associated with subduction zones and hot spots. The local geological characteristics that favor useful resources include relatively shallow resource depths to high permeability in the rocks surrounding the resource, and adequate resource fluids.

Exploration starts with the analysis of available geological information to identify the potential target. Once the target is identified, geochemical studies and core drilling are undertaken. These studies are complemented or sometimes preceded by geophysical surveys including aeromagnetic or resistivity studies and remote infrared and hyperspectral techniques.

Hydrothermal systems have different chemical properties (► Hydrothermal Systems, Geochemistry of). The source of heat is usually a magma chamber a few kilometers below the surface. Less frequently, the source of heat is a crustal site. Fluid origin is meteoric, that is, rainwater which infiltrates the ground to depths of a few kilometers. The permeability and degree of fracturing of this cap rock varies from site-to-site according to the intensity and abundance of the surface hydrothermal systems manifestations (boiling springs, steam vents, hot ponds, and geysers).

In the early stages of a hydrothermal system exploration, when there is only surface evidence, the aim of a geochemical survey is the generation of a model that evaluates the temperature and chemical conditions of the fluid at depth.

Drilling is the process for extracting geothermal energy resources for energy production utilization (► Geothermal Resources, Drilling for). Shallow or intermediate-depth wells may be drilled for the purposes of space heating or direct heat uses; more substantial drilling activities are needed to drill for hotter resources designed for power generation.

Geothermal drilling is a niche within the larger drilling services industry which focuses primarily on

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oil, gas, and minerals. In particular, deep drilling, required in most exploration programs for geothermal power generation projects, will likely utilize big rigs typical in oil and gas extraction.

There are several aspects unique to geothermal drilling. Mainly, geothermal formations, by nature, involve elevated temperatures which are usually significantly higher than those experienced when drilling for oil and gas. The rock that hosts these formations are typically harder (granite, granodiorite, quartzite, basalt, volcanic tuff), more abrasive, highly fractured, and under-pressured. Caustic elements may be present that can cause corrosion and scaling in the wellbore.

These unique characteristics present challenges in dealing with geothermal wells which, unlike oil and gas wells, do not produce economically until utilized through electric generation or direct uses. For power production, geothermal wells must be of a larger diameter than oil and gas wells to produce necessary flow rates for commercial production. Depths of geothermal wells vary according to location. Some resources are shallow (<1,000 m) and others deep (2,500 m to over 3,000 m).

Reservoir Engineering is the comprehensive integration of all available surface and underground information regarding geology, geophysics, geochemistry, well drilling-testing, exploitation data, information concerning the geothermal developer and objectives of a geothermal development: market targets, costs, and finance becoming the most powerful tools to evaluate the feasibility (▶ Reservoir Engineering in Geothermal Fields). As in any scientific or engineering activity, results derived from reservoir engineering depend on the quantity and quality of collected information and the as well as the assimilated handling and in depth comprehension of the collected information. Reservoir engineering is not limited to the final numerical tool, but also includes acquisition information which allows prediction of the impacts on a geothermal resource 20–30 years into the future.

Maintaining the sustainability of a geothermal field through operation requires Monitoring (▶ Geothermal Field and Reservoir Monitoring). Using techniques such as down-hole monitoring and surface monitoring, the impact of production on the long-term sustainability of a geothermal field can be closely evaluated to ensure that the resource is not prematurely cooling and that any cooling is minimal.

The heat stored in hot dry rock is not accessible via conventional geothermal technology. New methods are being developed and tested to access the huge potential of this type of resources (▶ Engineered Geothermal Systems, Development and Sustainability of). Commercialization of this technology could unlock many thousands of megawatts of power. For example, the estimate of the Technical Potential for EGS in the USA is estimated at 100 GWe, which is 30 times the total current installed US geothermal capacity from all energy sources. There has been some success, but no actual production from EGS reservoirs as of the end of 2010. Once commercialized, EGS needs to be proved sustainable.

As with any other geothermal energy source, EGS development involves some impact on the environment (▶ Geothermal Resources, Environmental Aspects of). Geothermal resources are environmentally important as natural thermal features. Typically, the most significant environmental impacts are associated with the exploitation of high-temperature liquid-dominated geothermal systems for electric power generation; however, the majority of these impacts can be avoided or minimized with appropriate techniques. However, as geothermal energy generally offsets use of fossil fuels, the use of geothermal resources are more likely to improve air quality and overall water quality.

The current utilization of geothermal resources worldwide includes direct use of heat and power generation (▶ Geothermal Energy Utilization). There is a long history of using geothermal heat since the Roman times. The development of geothermal usage began early in the twentieth century in industrial countries with abundant geothermal activity. The list of these countries includes Italy, USA, Japan, New Zealand and Iceland. In addition, developing countries such as the Philippines, Indonesia, Central America and Kenya are also listed as geothermal users.

Applications, such as space heating, agriculture, and other processes, require heat that may otherwise be provided using a fossil fuel (▶ Geothermal Resources Worldwide, Direct Heat Utilization of).

Recent developments in using geothermal sources in large-scale projects include district heating, greenhouse complexes, and major industrial uses. Heat exchangers are also becoming more efficient and better adapted to geothermal projects. This allows the use of lower-temperature water and highly saline fluids. Heat pumps utilizing very low-temperature fluids have extended geothermal developments into traditionally non-geothermal countries such as Canada, France, and Switzerland, as well as areas of the USA.

With the end of 2010, global use of direct geothermal utilization added to approximately 50.5 GW of thermal energy, in 78 countries, displacing over 121 TWh/year of energy consumption.

The techniques used for the conversion of geothermal fluid heat content into mechanical power are similar to those used in fossil-fueled power plants (▶ Geothermal Power Conversion Technology). Power conversion is the most predictable part of a geothermal project, as it consists of a straightforward engineering design with work executed by experienced manufacturers, engineering firms, and contractors.

The risks and challenges are related to exploration, drilling, and managing the resource. Optimization depends on the adaptation of the power station configuration to the available resources.

Today, 10,000 MW of geothermal power plants are in operation and a majority of them use steam turbines that operate on dry steam or steam produced by single or double flash with about 1,000 MW using Organic Rankine Cycles (ORC) or geothermal combined cycles. However, to widen the range of resources suitable for power generation beyond dry steam and flashed steam plants, ORC cycles have been implemented in the last 30 years, and will probably continue to grow as a common technology driving future development of geothermal resources.

Operational experience confirms the advantages of ORC power stations, not only for low-enthalpy water-dominated resources, but also for certain high-enthalpy sources where the brine is aggressive or the fluid contains a high percentage of non-condensable gas. The higher installation cost of these systems is often justified by environmental and long-term resource management considerations.

In geothermal systems, it is possible to estimate the commercial, sustainable, and renewable capacities of a geothermal system (▶ Geothermal Power Capacity, Sustainability and Renewability of). Sustainability is defined as the ability to economically maintain an installed power capacity over the amortized life of a power plant. This is done by taking practical steps, such as drilling "make-up" wells as required to compensate for resource degradation. Renewability is defined as the ability to maintain an installed power capacity indefinitely without encountering any resource degradation. Typically, the renewable power capacity at a geothermal site is generally too small for commercial development of electrical power capacity, but may be adequate for district heating or other direct uses of the geothermal energy.

The cost in producing geothermal resources for electric generation is important (▶ Geothermal Power Economics). In particular, the levelized cost of power is the applicable measurement for the cost of geothermal energy. Unlike fossil fuel power plants, most of the capital costs are incurred upfront in the development of the resource. Power cost is an objective criterion that favors the geothermal solutions compared to other alternative energy sources. However, the costs are heavily tied to the resource and the need for make-up well drilling to maintain full generation capacity.

Geothermal Resources Worldwide, Direct Heat Utilization of

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Article Outline

Glossary

Agribusiness applications In the geothermal context, they are the heating of greenhouses and open ground for various crops, aquaculture ponds and raceways heating for various aquatic species, and the heating of animal pens and houses in an effort to increase production and shorting the growing cycle.

Balneology The science of healing qualities of baths, especially with natural mineral waters and the therapeutic use of natural warm or mineral winters.

District heating Heating of more than one building from a central heating plant with the heated fluid provided through a central distribution systems of pipes.

Heat exchanger A device for transferring heat from one fluid to another. The fluids are usually separated by conducting walls of metal or plastic.

Heat pump A device which, by the consumption of work or heat, effects the transport of heat between a lower temperature to a higher temperature source. The useful output is heat in conventional usage. The reverse process is called a refrigerator used for the removal of heat.

Joule (J) The SI unit for all forms of energy or work. It is equal to 1 W-s or 0.239 cal.

Spa A resort using mineral water for bathing, soaking, and drinking along with covering portions of the body with mineral muds for therapeutic purposes. Diet, exercise, and rest can also be part of the spa treatment plan.

Watt (W) A unit of power or energy produced over time, equivalent to 1 J/s, or 0.001341 horse power (hp).

Definition of the Subject

Direct or non-electric utilization of geothermal energy refers to the immediate use of the heat energy rather than to its conversion to some other form such as electrical energy. The primary forms of direct-use include heating swimming pools and baths, and for balneology (therapeutic use), space heating and cooling including district heating, agriculture (mainly greenhouse heating, crop drying, and some animal husbandry), aquaculture (mainly fish pond and raceway heating), providing heat for industrial processes, and heat pumps (for both heating and cooling). In general, the geothermal fluid temperatures required for direct heat use are lower than those for economic electric power generation, and as a result these resources are available in most countries.

Most direct-use applications use geothermal fluids in the low-to-moderate temperature range between 50°C and 150°C, and in general, the reservoir can be exploited by conventional water well drilling equipment. Low-temperature systems are also more widespread than high-temperature systems (above 150°C), so they are more likely to be located near potential users. In the USA, for example, of the 1,350 known or identified geothermal systems, 5% are above 150°C, and 85% are below 90°C [1]. In fact, almost every country in the world has some low-temperature systems, while only a few have accessible high-temperature systems.

Geothermal energy is a renewable energy since the tapped heat is continuously renovated by natural process of the Earth's interior, and the extracted geothermal fluids are replenished by natural recharge and by reinjection of the exhausted fluids, providing a sustainable development. Using geothermal

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Geothermal Resources Worldwide, Direct Heat Utilization of. Table 1 The leading direct-use countries (2010)

Country	Energy use TJ/year	Energy use GWh/year	Power MWt	Capacity Factor	Main applications
China	75,348	20,932	8,898	0.27	Bathing/district heating
USA	56,552	15,710	12,611	0.14	GHP
Sweden	45,301	12,585	4,460	0.32	GHP
Turkey	36,886	10,247	2,084	0.56	District heating
Japan	25,698	7,139	2,100	0.39	Bathing (onsens)
Iceland	24,361	6,768	1,826	0.42	District heating
France	12,929	3,592	1,345	0.30	District heating
Germany	12,764	3,546	2,485	0.16	Bathing/district heating
The Netherlands	10,699	2,972	1,410	0.24	GHP
Italy	9,941	2,762	867	0.36	Spas/space heating
Hungary	9,767	2,713	655	0.47	Spas/greenhouses
New Zealand	9,552	2,654	393	0.77	Industrial uses
Canada	8,873	2,465	1,126	0.25	GHP
Switzerland	7,715	2,143	1,061	0.23	GHP

minimizing the greenhouses gases and particulates that are produced from using fossil fuels, and also provides energy independence since it is a domestic resource. The environmental impact of direct-use of geothermal energy is negligible as in most cases, once the heat is extracted from the fluid, the spent fluid is reinjected back into the ground, thus preventing the release of harmful gasses and particulates.

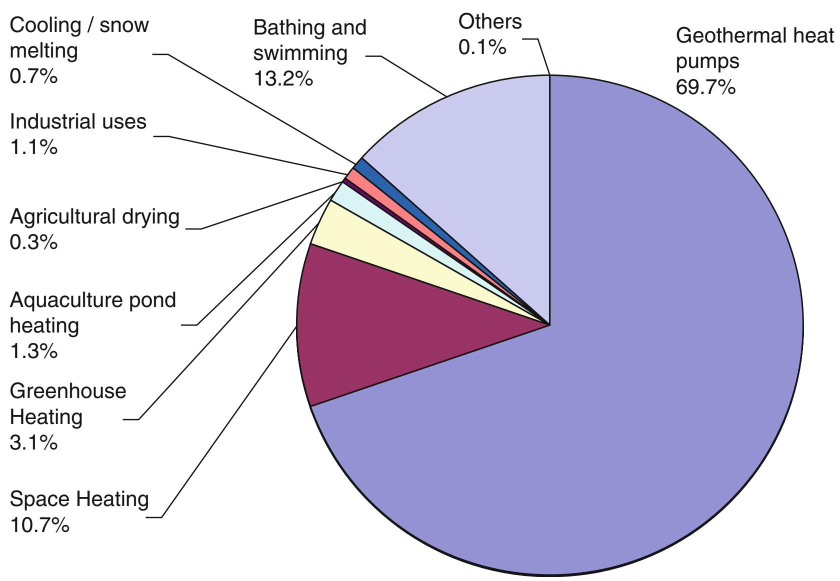
Introduction

Traditionally, direct use of geothermal energy has been on small scale by individuals. More recent developments involve large-scale projects, such as district heating (Iceland and France), greenhouse complexes (Hungary and Russia), or major industrial use (New Zealand, Iceland, and the USA). Heat exchangers are also becoming more efficient and better adapted to geothermal projects, allowing use of lower temperature water and highly saline fluids. Heat pumps utilizing very low-temperature fluids (5–30°C) have extended geothermal developments into traditionally non-geothermal countries such as Canada, France, Switzerland, and Sweden, as well as areas of the midwestern and eastern USA. Most equipments used in these projects are of standard, off-the-shelf design and need only slight modifications to handle geothermal fluids [2, 3].

Worldwide [4], the installed capacity of direct geothermal utilization is 50,583 MWt, and the energy use is 438,071 TJ/year (121,686 GWh/year), distributed among 78 countries; the leading countries are presented in Table 1. This amounts to saving an equivalent 45.2 million tons of fuel oil per year (TOE) if it replaces electricity . The distribution of the energy use among the various types is listed in Table 2 and shown in Fig. 1 for the worldwide installed capacity, and Fig. 2 for the annual energy use. For comparison, the installed capacity in the USA (2010) is 12,611 MWt, and the annual energy use is 56,552 TJ (15,709 GWh), saving 20.2 million barrels of oils (3.04 million TOE) [5]. Internationally, the largest energy uses are for geothermal heat pumps (GHP) (49%), and swimming, bathing, and balneology (25%); and similar, in the USA, the largest use is for geothermal heat pumps (84%). In comparison, Iceland's largest geothermal energy use is 72% for district heating 17,483 TJ/year (4,857GWh/year) [6]. As can be seen from Tables 1 and 2, heat

Geothermal Resources Worldwide, Direct Heat Utilization of. Table 2 Summary of geothermal direct-use by category (2010)

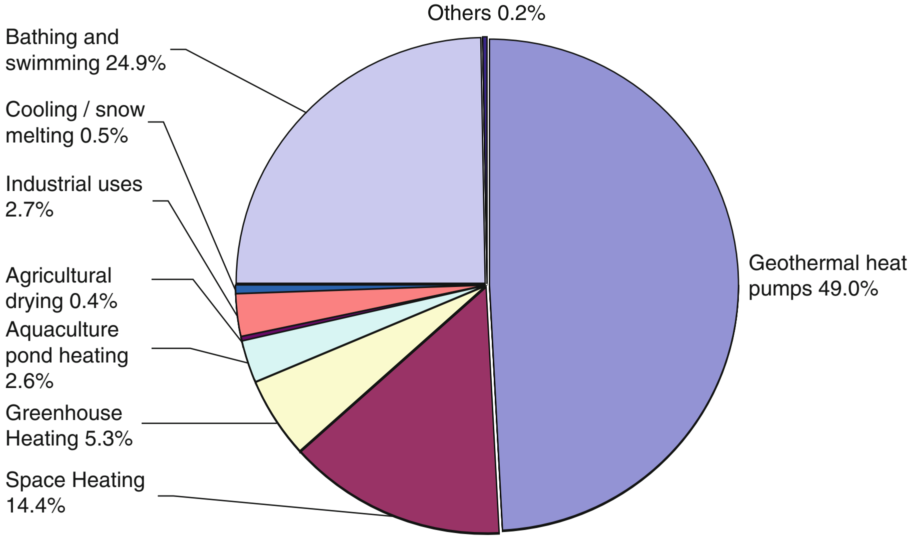
Category	Utilization (TJ/year)	Utilization (GWh/year)	Capacity (MWt)	Capacity factor
Geothermal heat pumps	214,782	59,662	35,236	0.19
Space heating	62,984	17,496	5,391	0.37
Greenhouse heating	23,264	6,462	1,544	0.48
Aquaculture pond heating	11,521	3,200	653	0.56
Agricultural drying	1,662	462	127	0.42
Industrial uses	11,746	3,263	533	0.70
Bathing and swimming	109,032	30,287	6,689	0.52
Cooling/snow melting	2,126	591	368	0.18
Others	956	266	41	0.73
Total	438,071	121,686	50,583	0.27



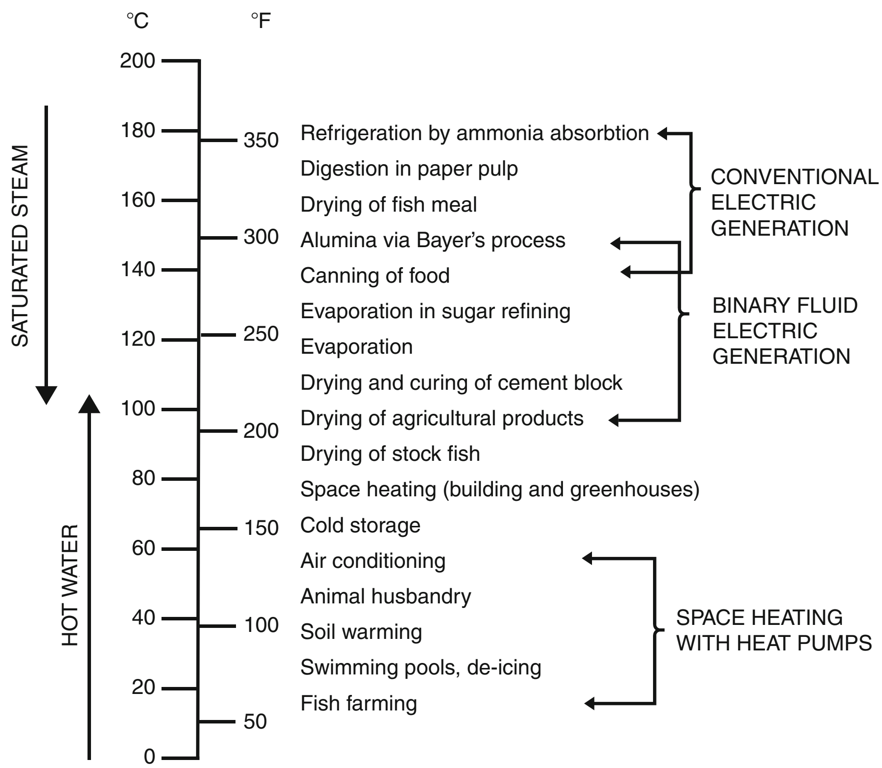
Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 1
Distribution of direct-use installed capacity (MWt) in the world (2010)

pumps have low load factors (USA), whereas industrial uses have high load factors (NZ) due to the more continuous annual use in industrial processing.

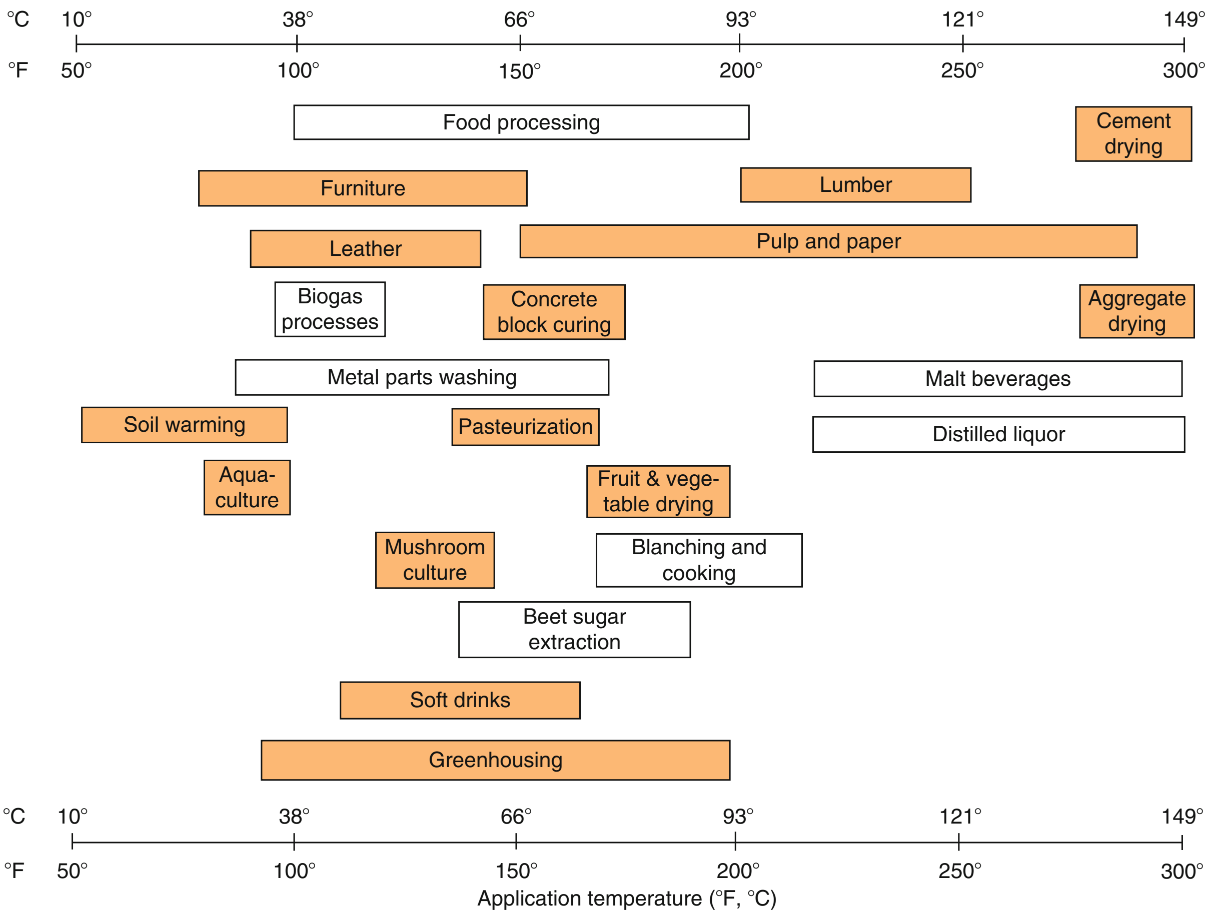
The Lindal diagram [7], named for Baldur Lindal, the Icelandic engineer who first proposed it, indicates the temperature range suitable for various direct-use activities (Fig. 3). Figure 4 indicates some of the worldwide direct-use applications along with their possible temperature range of use. Typically, the agricultural and aquacultural uses require the lowest temperatures, with values from 25°C to 90°C. The amounts and types of chemicals, such as arsenic and dissolved gases such as boron, are a major problem with plants and animals; thus, heat exchangers are often necessary. Space heating



Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 2
Distribution of direct-use annual energy use (TJ/year) in the world (2010)



Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 3
Lindal diagram



Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 4
Examples of industrial applications of geothermal energy with the colored bars indicating those currently using geothermal energy in the world

requires temperatures in the range of 50–100°C, with 40°C useful in some marginal cases and ground-source heat pumps extending the range down to 5°C. Cooling and industrial processing normally require temperatures over 100°C. The leading user of geothermal energy, in terms of market penetration, is Iceland, where more than 89% of the population enjoys geothermal heat in their homes from 30 municipal district heating services, and 54% of the country's total energy use is supplied by direct heat and electrical energy derived from geothermal resources [6].

Swimming, Bathing, and Balneology

People have used geothermal water and mineral waters for bathing and their health for many thousands of years. Balneology, the practice of using natural mineral water for the treatment and cure of disease, also has a long history. A spa originates at a location mainly due to the water from a spring or well. The water, with certain mineral constituents and often warm, give the spa certain unique characteristics that will attract customers. Associated with most spas is the use of muds (peoloids) which either are found at the site or are imported from special locations. Drinking and bathing in the water, and using the muds are thought to give certain health benefits to the user. Swimming pools have desirable temperature at 27°C; however, this will vary from culture to culture by as much as 5°C. If the geothermal water is higher in temperature, then some sort of mixing or cooling by aeration or in a holding pond is required to lower the temperature, or it can first be used for space heating, and then

cascaded into the pool. If the geothermal water is used directly in the pool, then a flow-through process is necessary to replace the "used" water on a regular basis. In many cases, the pool water must be treated with chlorine; thus, it is more economical to use a closed loop for the treated water and have the geothermal water provide heat through a heat exchanger [8].

Romans, Chinese, Ottomans, Japanese, and central Europeans have bathed in geothermal waters for centuries. Today, more than 2,200 hot springs resorts in Japan draw 100 million guests every year, and the "return-to-nature" movement in the USA has revitalized many hot spring resorts.

The geothermal water at Xiaotangshan Sanitarium, northwest of Beijing, China, has been used for medical purposes for over 500 years. Today, the 50°C water is used to treat high blood pressure, rheumatism, skin disease, diseases of the nervous system, ulcers, and generally for recuperation after surgery. In Rotorua, New Zealand, at the center of the Taupo Volcanic Zone of North Island, the Queen Elizabeth Hospital was built during World War II for US servicemen and later became the national hospital for the treatment of rheumatic disease. The hospital has 200 beds, and outpatient service, and a cerebral palsy unit. Both acidic and basic geothermally heated mud baths treat rheumatic diseases.

In Beppu, on the southern island of Kyushu, Japan, the hot water and steam meet many needs: heating, bathing, cooking, industrial operations, agriculture research, physical therapy, recreational bathing, and even a small zoo [9]. The waters are promoted for "digestive system troubles, nervous troubles, and skin troubles." Many sick and crippled people come to Beppu for rehabilitation and physical therapy. There are also eight Jigokus (hot springs or geysers called "burning hells") in town, showing various geothermal phenomena, used as tourist attractions.

In the former Czechoslovakia, the use of thermal waters has been traced back before the occupation of the Romans and has had a recorded use of almost 1,000 years. Today, there are 60 spa resorts located mainly in Slovakia, visited by 460,000 patients usually for an average of three weeks each. These spas have old and well-established therapeutic traditions. Depending on the chemical composition of the mineral waters and spring gas, availability of peat and sulfurous mud, and climatic conditions, each sanatorium is designated for the treatment of specific diseases. The therapeutic successes of these spas are based on centuries of healing tradition (balneology), systematically supplemented by the latest discoveries of modern medical science [10].

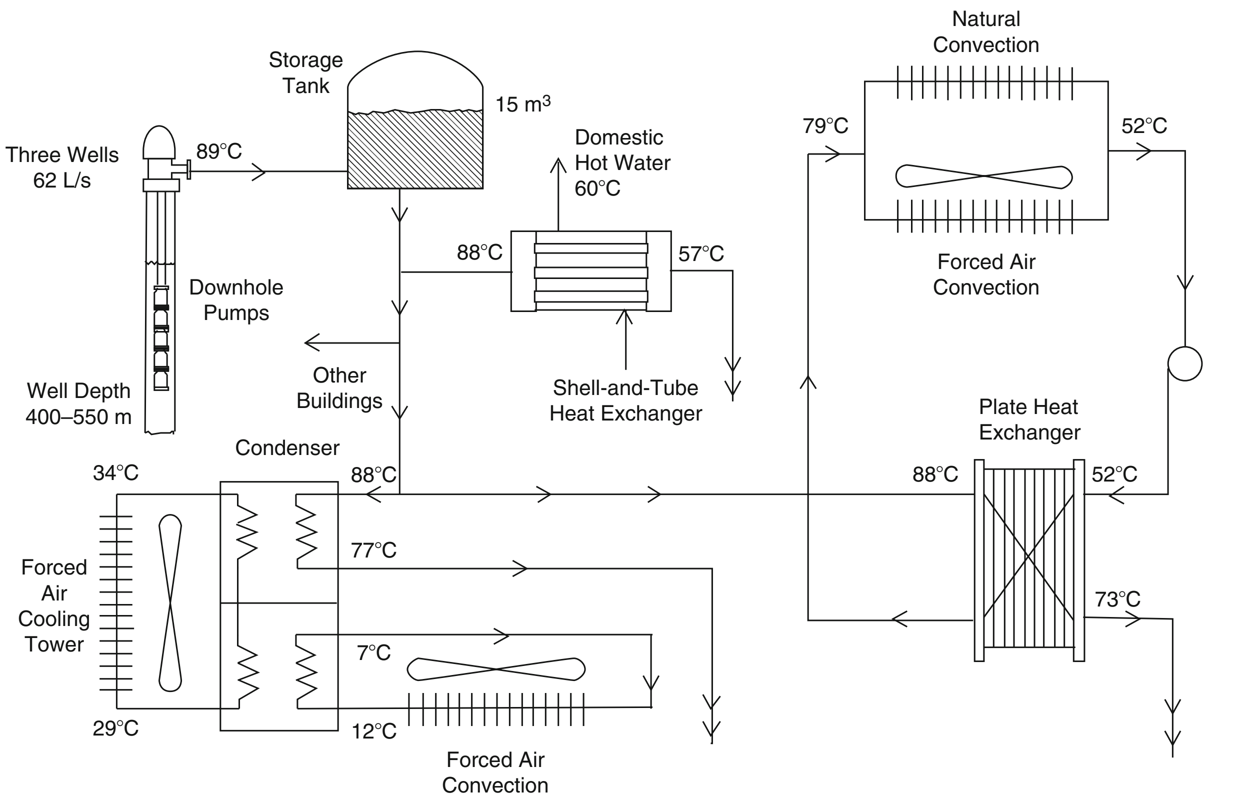
Bathing and therapeutic sites in the USA include: Saratoga Springs, New York; Warm Springs, Georgia; Hot Springs, Virginia; White Sulfur Springs, West Virginia; Hot Spring, Arkansas; Thermopolis, Wyoming; and Calistoga, California. The original use of these sites was by Indians, where they bathed and recuperated from battle as neutral ground. There are over 115 major geothermal spas in the USA with an annual energy use of 1,500 TJ [8].

Figures for this use are difficult to collect and quantify. Almost every country has spas and resorts that have swimming pools (including balneology), but many allow the water to flow continuously, regardless of use. As a result, the actual usage and capacity figures may be high. Undeveloped natural hot springs have not been included in the data. A total of 67 countries have reported bathing and swimming pool use, amounting to a worldwide installed capacity of 6,689 MWt and energy used of 109,032 TJ/year (30,287 GWh/year) based on data from country update papers from the World Geothermal Congress 2010 (WGC2010) in Bali, Indonesia [4].

Space Conditioning

Space conditioning includes both heating and cooling. Space heating with geothermal energy has widespread application, especially on an individual basis. Buildings heated from individual wells are popular in Klamath Falls, Oregon; Reno, Nevada, USA; and Taupo and Rotorua, New Zealand. Absorption space cooling with geothermal energy has not been popular because of the high-temperature requirements and low efficiency. However, newer units recently placed on the market report to use temperatures below 100°C efficiently. Geothermal heat pumps (groundwater and ground-coupled) have become popular in the USA, Canada, China, and Europe, used for both heating and cooling.

Downhole heat exchangers have been used for heating individual buildings using a closed loop of pipe in a well extracting only heat in Klamath Falls, Oregon, Reno, Nevada, Rotorua, New Zealand, and Izmir, Turkey (see the "Heat Exchanger" section for more details). An example of space heating and cooling



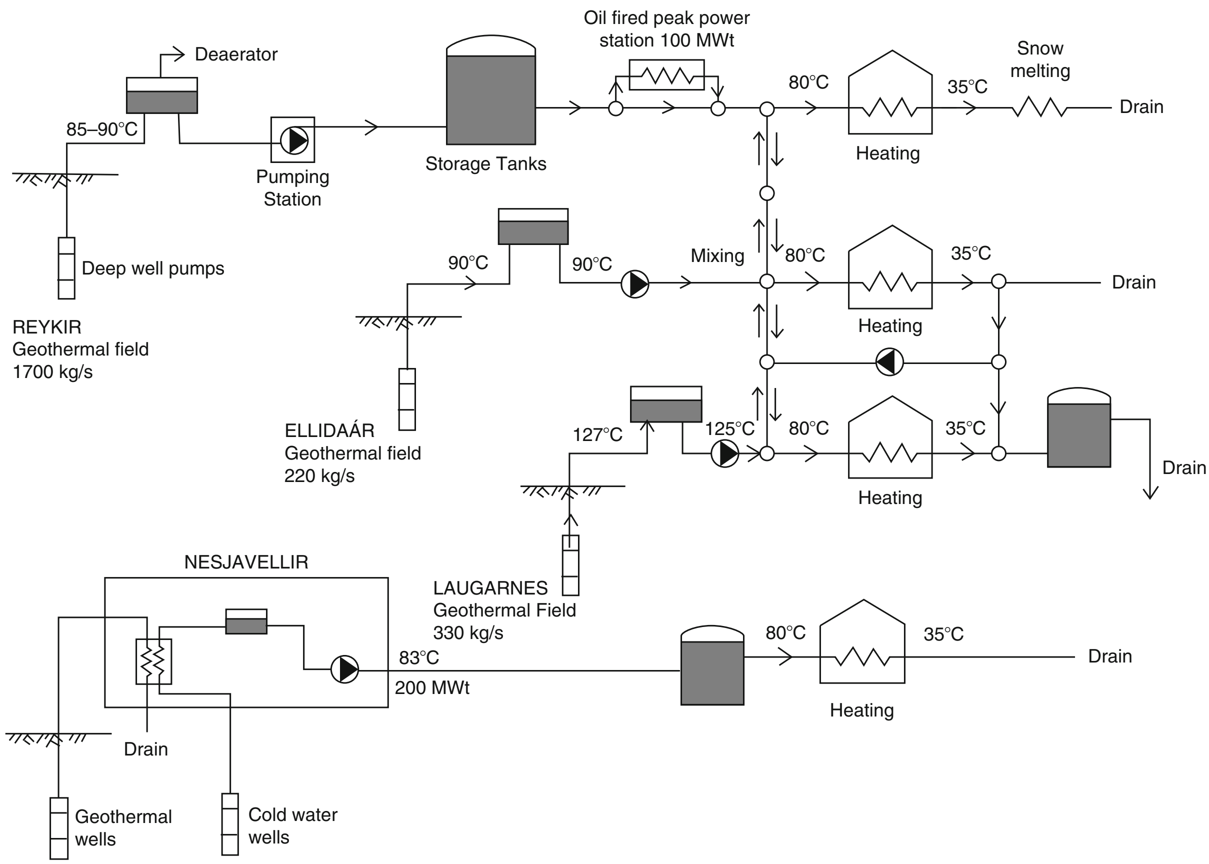
Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 5
Oregon Institute of Technology heating and cooling system

with low-to-moderate temperature geothermal energy is the Oregon Institute of Technology in Klamath Falls, Oregon (Fig. 5). Here, 12 buildings (approximately 70,000 m^2 of floor space) are heated with water from three wells at 89°C. Up to 62 L/s of fluid can be provided to the campus, with the average heat utilization rate over 0.53 MWt and the peak at 5.6 MWt. In addition, a 541 kW (154 t) chiller requiring up to 38 L/s of geothermal fluid produces 23 L/s of chilled fluid at 7°C to meet the campus cooling base load (recently decommissioned) [11, 12].

Space heating is reported in 27 countries with an installed capacity of 752 MWt and annual energy use of 9,609 TJ (2,669 GWh) based on data from country update reports presented at WGC2010 in Bali, Indonesia [4].

District Heating

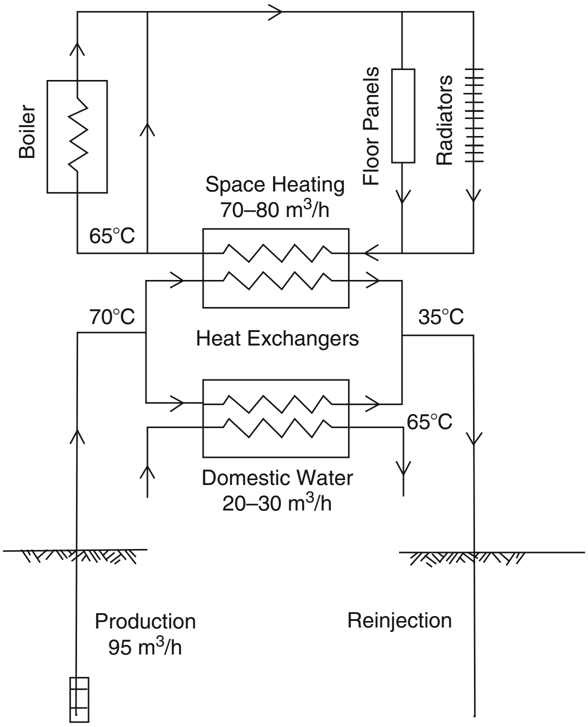
District heating involves the distribution of heat (hot water or steam) from a central location through a network of pipes to individual houses or blocks of buildings. The distinction between a district heating and space heating system is that space heating usually involves one geothermal well per structure, whereas district heating involves serving multiple buildings from a well or well field. The heat is used for space heating and cooling, domestic water heating, and industrial process heat. A geothermal well field is the primary source of heat; however, depending on the temperature, the district may be a hybrid system, which would include fossil fuel and/or heat pump peaking. An important consideration in district heating projects is the thermal load density, or the heat demand divided by the ground area of the district. A high heat density, generally above 1.2 GJ/h/ha or a favorability ratio (heat load available/heat load on the system) of 2.5 GJ/ha/year, is recommended. Often fossil fuel peaking is used to meet the coldest period, rather than drilling additional wells or pumping more fluids, as geothermal can usually meet 50% of the load 80–90% of the time, thus improving the efficiency and economics of



Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 6
Reykjavik district heating system

the system [13]. Geothermal district heating systems are capital intensive. The principal costs are initial investment costs for production and injection wells, downhole and circulation pumps, heat exchangers, pipelines and distribution network, flow meters, valves and control equipment, and building retrofit. The distribution network may be the largest single capital expense at approximately 35–75% of the entire project cost. Operating expenses, however, are in comparison lower and consists of pumping power, system maintenance, control, and management. The typical savings to consumers range from approximately 30–50% per year of the cost of natural gas.

Geothermal district heating systems are in operation in 24 countries, including large installations in Iceland, France, Poland, Hungary, Turkey, Japan, China, Romania, and the USA. The Warm Springs Avenue project in Boise, Idaho, dating back to 1892 and originally heating more than 400 homes, supplies hot water or steam through a network of pipes to individual dwellings or blocks of buildings [14]. The Reykjavik, Iceland, district heating system (Fig. 6) is probably the most famous [15, 16]. This system supplies heat for a population of around 200,000 people. The installed capacity of 1,240 MWt with peak load of 924 MWt is designed to meet the heating load to about $-10°C$; however, during colder periods, the increased load is met by large storage tanks and an oil-fired booster station. The total pipeline length is 3,846 km and almost 80 million cubic meters of water are delivered annually [6]. In France, production wells in sedimentary basins provide direct heat to more than 500,000 people in 170,000 dwellings from 34 projects with an installed capacity of 300 MWt and annual energy use of 4,900 TJ/year [17]. These wells provide from 40°C to 100°C water from depths of 1,500–2,000 m. In the Paris basin,



Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 7
Melun l'Almont (Paris) doublet heating system

a doublet system (one production and one injection well direction drilled from on site) provides 70°C water, with the peak load met by heat pumps and conventional fossil fuel burners (Fig. 7).

The total installed capacity for the 24 countries is 4,639 MWt and the annual energy use is 53,375 TJ (12,857 GWh) as reported in WGC2010 [4].

Agribusiness Applications

Agribusiness applications (agriculture and aquaculture) are particularly attractive because they require heating at the lower end of the temperature range where there is an abundance of geothermal resources. Use of waste heat or the cascading of geothermal energy also has excellent possibilities. A number of agribusiness applications can be considered: greenhouse heating, aquaculture and animal husbandry facilities heating, soil warming and irrigation, mushroom culture heating and cooling, and biogas generation.

Numerous commercially marketable crops have been raised in geothermally heated greenhouses in Hungary, Russia, New Zealand, Japan, Iceland, China, Tunisia, and the USA. These include vegetables, such as cucumbers and tomatoes, flowers (both potted and bedded), house plants, tree seedlings, and cacti. Using geothermal energy for heating reduces operating costs (which can account for up to 35% of the product cost) and allows operation in colder climates where commercial greenhouses would not normally be economical.

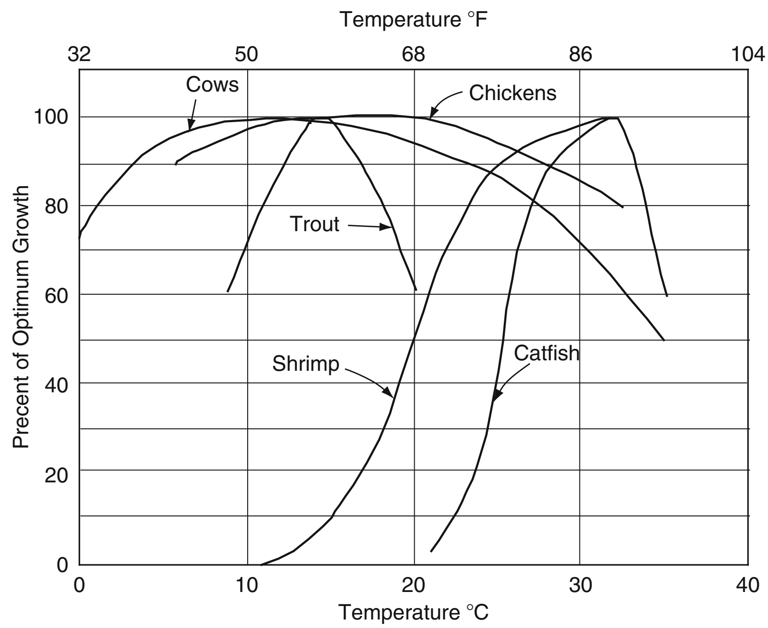
The use of geothermal energy for raising catfish, shrimp, tilapia, eels, and tropical fish has produced crops faster than by conventional solar heating. Using geothermal heat allows better control of pond temperatures, thus optimizing growth (Fig. 8). Fish breeding has been successful in Japan, China, and the USA. A very successful prawn raising operation, producing 400 t of Giant Malaysian Freshwater Prawns per year at US $17 to 27/kg has been developed near the Wairakei geothermal field in New Zealand [18]. The most important factors to consider are the quality of the water and disease. If geothermal water is used directly, concentrations of dissolved heavy metals, fluorides, chlorides, arsenic, and boron must be considered, and if necessary, isolated by using a heat exchangers.

Livestock raising facilities can encourage the growth of domestic animals by a controlled heating and cooling environment. An indoor facility can lower mortality rate of newborn, enhance growth rates, control diseases, increase litter size, make waste management and collection easier, and in most cases improve the quality of the product. Geothermal fluids can also be used for cleaning, sanitizing and drying of animal shelters and waste, as well as assisting in the production of biogas from the waste.

Agribusiness uses of geothermal energy are reported in 38 countries with an installed capacity of 2,197 MWt and annual energy use of 34,785 TJ (9,662 GWh) according to WGC2010 reports [4]. Approximately two thirds of the use is for greenhouse applications, with the remaining in aquaculture production.

Industrial Applications and Agricultural Drying

Although the Lindal diagram and the current direct-use diagram (Figs. 3 and 4) shows many industrial and process applications of geothermal energy, the world's



Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 8
Effect of temperature on animal and fish growth

uses are relatively few. The oldest industrial use is at Larderello, Italy, where boric acid and other borate compounds have been extracted from geothermal brines since 1790. Today, the two largest industrial uses are the diatomaceous earth drying plant in northern Iceland and a pulp, paper and, wood processing plant at Kawerau, New Zealand. Notable US examples are two onion dehydration plants in northern Nevada [19], and a sewage digestion facility in San Bernardino, California. Alcohol fuel production has been attempted in the USA; however, the economics were marginal and thus this industry has not been successful. With the recent increase in fossil fuel prices, there has been renewed interest in producing ethanol and biodiesel using geothermal energy [20].

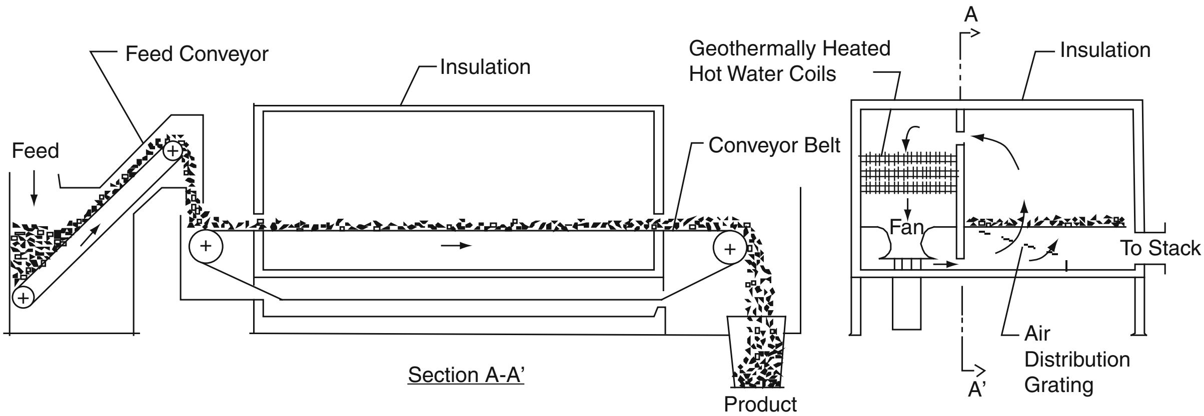
A new development in the use of geothermal fluids is the enhanced heap leaching of precious metals in Nevada by applying heat to the cyanide process [21]. Using geothermal energy increases the efficiency of the process and extends the production into the winter months.

Drying and dehydration are important moderate-temperature uses of geothermal energy. Various vegetable and fruit products are feasible with continuous belt conveyors or batch (truck) dryers with air temperatures from 40°C to 100°C as shown in Fig. 9 [22]. Geothermally drying alfalfa, onions, garlic, pears, apples, and seaweed are examples of this type of direct-use.

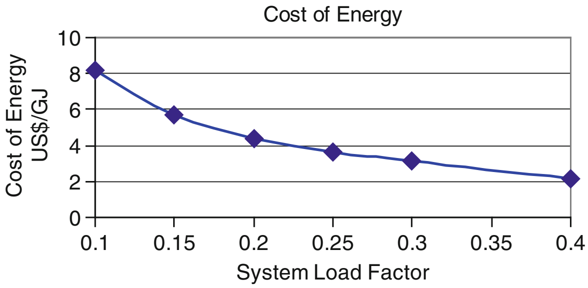
An example of a small-scale food dehydrator is one located in northeastern Greece where 4 t of tomatoes are dried annually, using 59°C geothermal water to dry 14 kg/h on racks placed in a long tunnel drier. The tomatoes are then placed in olive oil for shipment and sale. The plant is only operated by three employees. At the other end of the spectrum is the large-scale onion and garlic drying facilities located in western Nevada, USA, employing 75 workers [23]. These continuous belt drier are fed 3,000–4,300 kg/h of onions at a moisture content of around 85%, and after 24 h, produce 500–700 kg/h of dried onions at moisture contents around 4%. These large belt driers are approximately 3.8 m wide and 60 m long.

A total of 20 countries reported industrial and agricultural drying applications from WGC2010 [4], with an installed capacity of 660 MWt and annual energy use of 13,408 TJ (3,724 GWh).

Industrial applications mostly need the higher temperature as compared to space heating, greenhouses, and aquaculture projects. Examples of industrial



Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 9
Continuous belt dehydration plant, schematic



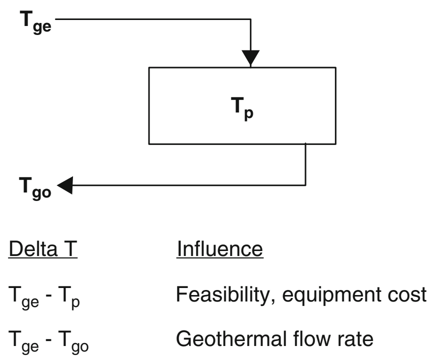
Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 10
Load factor versus cost of energy (Modified from Rafferty [24])

operations that use geothermal energy are: heap leaching operations to extract precious metals in the USA (110°C), dehydration of vegetables in the USA (130°C), diatomaceous earth drying in Iceland (180°C), and pulp and paper processing in New Zealand (205°C). Drying and dehydration may be the two most important process uses of geothermal energy. A variety of vegetable and fruit products can be considered for dehydration at geothermal temperatures, such as onions, garlic, carrots, pears, apples, and dates. Industrial processes also make more efficient use of the geothermal resources as they tend to have high load factors in the range of 0.4–0.7. High load factors reduce the cost per unit of energy used as indicated in Fig. 10 [24].

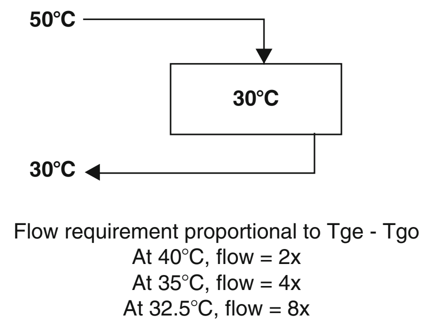
Direct-Use Temperature Requirements

The design of mechanical systems involving heat transfer, such as direct-use geothermal systems, is heavily influenced by temperature. Temperature difference (delta T or ΔT) is particularly important as it frequently governs feasibility, equipment selection, and flow requirements for the system. Rafferty [25] addresses these issues with several "rules of thumb" that are described below. He introduces the material with the following discussion:

- Two primary temperature differences govern feasibility, flow requirements, and design of direct-use equipment. These are illustrated in a simplified way in Fig. 11. The first is the difference between the geothermal temperature entering the system (T_{ge}) and the process temperature (T_p). This difference determines whether or not the application will be feasible. For a direct-use project, the temperature of the geothermal entering the system must be above the temperature of the process in order to transfer heat out of the geothermal water and into the process (aquaculture pond, building, greenhouse, etc.). Beyond that, it must be sufficiently above the process to allow the system to be constructed with reasonably sized heat-transfer equipment. The greater the temperature difference between the geothermal resource and the process, the lower the cost of heat exchange equipment. The key question is how much above the process temperature does the geothermal need to be for a given application.



Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 11
Fundamental direct-use temperature differences [25]



Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 12
Direct pool/pond heating (Modified from Rafferty [25])

The second temperature difference is the one between the geothermal entering the system and leaving the system (T_{ge} vs T_{go} in Fig. 11). This determines the geothermal flow rate necessary to meet the heat input requirement of the application. The greater the temperature difference between the entering and leaving temperatures, the lower the geothermal flow required. Obviously, the resource temperature is fixed. The process temperature plays a role as well since the leaving geothermal temperature cannot be lower than the process temperature to which it is providing heat. In addition, the specifics of the application and the heat transfer equipment associated with it also influence the temperature required. There are two broad groups of applications with similar characteristics in terms of heat transfer–aquaculture and pools, greenhouses, and building space heating.

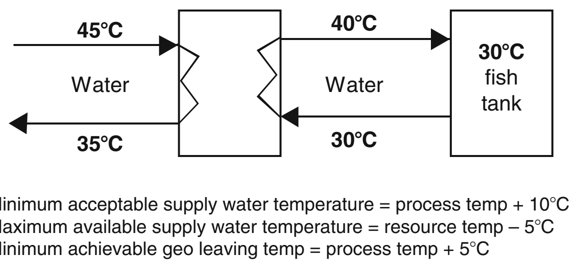
Pool and Aquaculture Pond Heating

Pond and pool heating is one of the simplest geothermal applications as it usually uses the geothermal water directly in the pond/pool to provide the required heat demand. This is illustrated in Fig. 12 [25], where 50°C geothermal water is supplied to heat the pool water to 30°C. Thus, the ΔT is 20°C, and using a flow rate of 10 L/s, the energy supplied would be 837 kW (3.0 GJ/h) (kW = L/s $\times$ ΔT $\times$ 4,184). If the supply temperature were instead 40°C, the flow rate would have to be doubled to provide the same amount of energy, and four times at 35°C, and eight times at 32.5°C.

If the geothermal water cannot be used directly due to health restrictions, then a heat exchanger is necessary to heat treated water for the pond or pool. Following the "rule of thumb" that the heated water to the pool should be 10°C above the pool temperature, then according to the previous example, 40°C secondary water would have to be provided to the pool. Using a heat exchanger between the geothermal water and the secondary water, an additional ΔT of 5°C is required to accommodate the heat transfer between the geothermal water and the secondary water. Thus, 45°C geothermal water would be required, and on the return side of the heat exchanger, the geothermal reject fluid should be 5°C above the return temperature of the secondary water. Thus, the rule of thumb is "10/5/5" as listed below in Fig. 13.

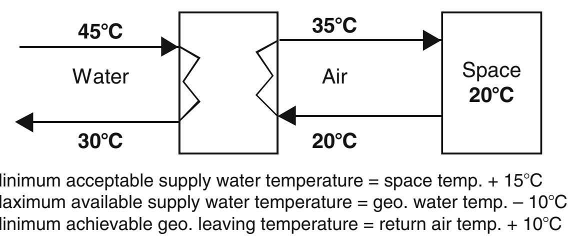
Greenhouse and Building Space Heating

Heating of greenhouses and building often involves the transfer of heat to the air in the structure using a water-to-air heat exchanger, called a coil, usually consisting of finned copper tubes [25]. The simplest version of this application is shown in Fig. 14. In order to heat the space, heated air should be delivered at least 15°C above the space temperature, 20°C shown in this example. Thus, the air should be delivered at 35°C or above from the water to the coil. The reason for the large difference, 15°C, is to limit the required quantity of air circulated to meet the heating requirements at reasonable levels. Also, as the difference becomes less, the fan and duct sizes become large, and the fan power



Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 13

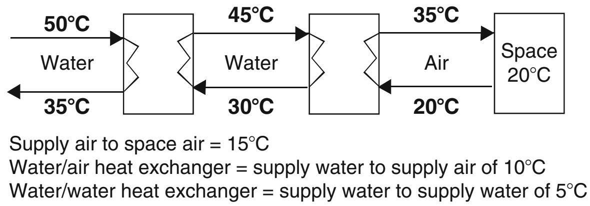
Pond/pool heating with heat exchanger (Modified from Rafferty [25]). Minimum acceptable supply water temperature = space temperature + 15°C. Maximum available supply water temperature = geothermal water temperature −10°C. Minimum achievable geothermal leaving temperature = return air temperature + 10°C



Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 14

Space heating without isolation heat exchanger (Modified from Rafferty [25]). Supply air to space air = 15°C. Supply air to space air = 15°C. Water/air heat exchanger = supply water to supply air of 10°C. Water/water heat exchanger = supply water to supply water of 5°C

consumption can be excessive. In addition, occupant comfort is important, as when the air supply drops below the 15°C difference, the temperature of the air approaches human skin temperature, which results in a "drafty" sensation to the occupants, even at the desired air temperature. In addition, the geothermal water delivered to the water-to-air heat exchangers should be at least 10°C above the required air temperature to limit the size and cost of this heat exchanger – usually a coil type. The same ΔT is required between the leaving geothermal water and the return air temperature. Thus, to supply 20°C heat to the room,



Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 15

Space heating 15/10/5 rule with geothermal isolation plate heat exchanger (Modified from Rafferty [25])

a geothermal resource temperature would have to be at least 45°C. The "rule of thumb" for this condition is then "15/10/10" as shown in Fig. 14.

The example above assumes that the geothermal water is suitable to flow directly through the water-to-air heat exchanger (coil); however, if hydrogen sulfide is present, then this gas will attack copper and solder in the coil and cause leakage and failure to the unit. Thus, in the case where the geothermal must be isolated from the heating system equipment, a plate heat exchanger is normally placed between the two circuits to protect the heating equipment [25]. A plate heat exchanger is then added to the left side of the equipment shown in Fig. 14 and resulting in the configuration shown in Fig. 15. All the temperatures shown in Fig. 14 are still valid; the difference is that the plate heat exchangers will require additional temperature input to maintain the space (home) temperature of 20°C. As in the previous example, a ΔT of 5°C is required between the geothermal supply and the output from the secondary water. Thus, the new geothermal temperature required to meet the needs of the system is 50°C. The return geothermal water can only be cooled to 35°C as a result of the intermediate water loop return temperature of 30°C and the required 5°C ΔT. This then provides of rule of thumb of "15/10/5" as described below Fig. 15.

In summary, the following is provided by Rafferty [25]:

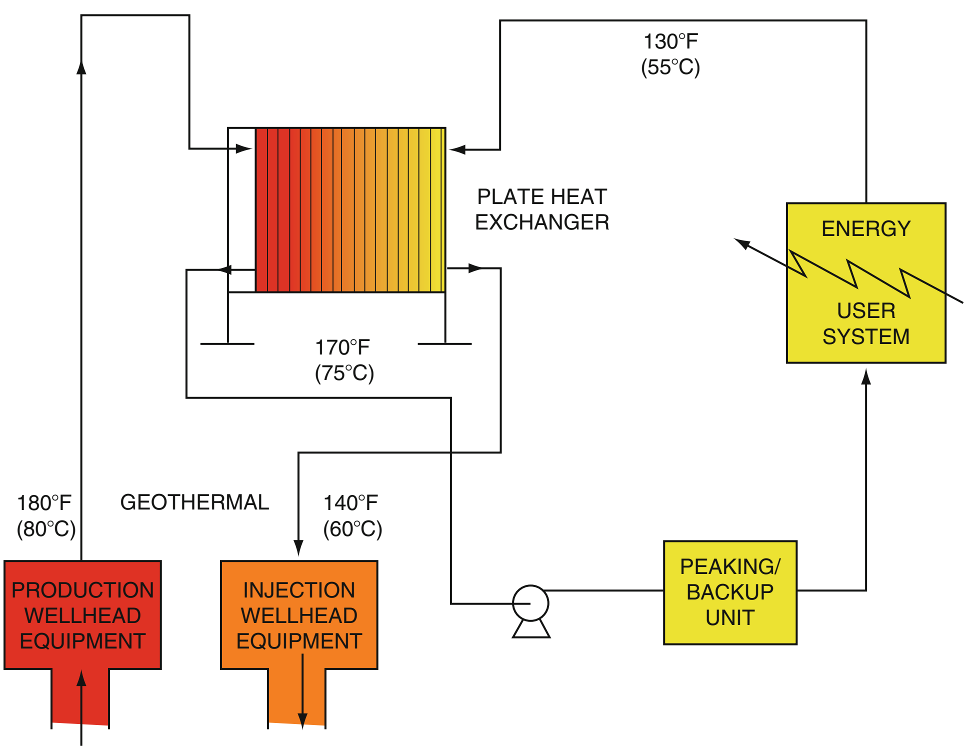
- All of the rules of thumb discussed here are exactly that. It is possible in all cases to "bend the rules," and design systems and equipment for temperatures closer than the guidelines provided above. The values provided here are intended for initial evaluation of

applications by those not in the practice of designing heating systems on a regular basis. The guidelines cited apply to new systems using commercially manufactured equipment. Homemade heat exchangers or existing equipment selected for water temperatures well above available geothermal temperature would require additional analysis.

Equipment

Standard equipment is used in most direct-use projects, provided allowances are made for the nature of geothermal water and steam. Temperature is an important consideration, so is water quality. Corrosion and scaling caused by the sometimes unique chemistry of geothermal fluids may lead to operating problems with equipment components exposed to flowing water and steam. In many instances, fluid problems can be designed out of the system. One such example concerns dissolved oxygen, which is absent in most geothermal waters, except perhaps the lowest temperature waters. Care should be taken to prevent atmospheric oxygen from entering district heating waters, for example, by proper design of storage tanks. The isolation of geothermal water by installing a heat exchanger may also solve this and similar water quality–derived problems. In this case, a clean secondary fluid is then circulated through the used side of the system as shown in Fig. 16.

The primary components of most low-temperature direct-use systems are downhole and circulation pumps, transmission and distribution pipelines, peaking or backup plants, and various forms of heat extraction equipment (Fig. 16). Fluid disposal is either surface or subsurface (injection). A peaking system may be necessary to meet maximum load. This can be done by increasing the water temperature or by providing tank storage (such as done in most of the Icelandic district heating systems). Both options mean that fewer wells need to be drilled thus requiring less geothermal fluid. When the geothermal water temperature is warm (below 50°C), heat pumps are often used.



Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 16
Geothermal direct-utilization system using a heat exchanger

The equipment used in direct-use projects represents several units of operations. The major units will now be described in the same order as seen by geothermal waters produced for district heating. Detailed discussion of equipment design and use can be found in Lund et al. [26].

Downhole Pumps

Unless the well is artesian, downhole pumps are needed, especially in large-scale direct utilization system. Downhole pumps may be installed not only to lift fluid to the surface, but also to prevent the release of gas and the resultant scale formation. The two most common types are: lineshaft pump systems and submersible pump systems.

The lineshaft pump system (Fig. 17) consists of a multistage downhole centrifugal pump, a surface mounted motor, and a long driveshaft assembly extending from the motor to the pump bowls. Most are enclosed, with the shaft rotating within a lubrication column which is centered in the production tubing. This assembly allows the bearings to be lubricated by oil as hot water may not provide adequate lubrication. A variable-speed drive set just below the motor on the surface can be used to regulate flow instead of just turning the pump on and off.

The electric submersible pump system (Fig. 18) consists of a multistage downhole centrifugal pump, a downhole motor, and a seal section (also called a protector) between the pump and motor, and electric cable extending from the motor to the surface electricity supply.

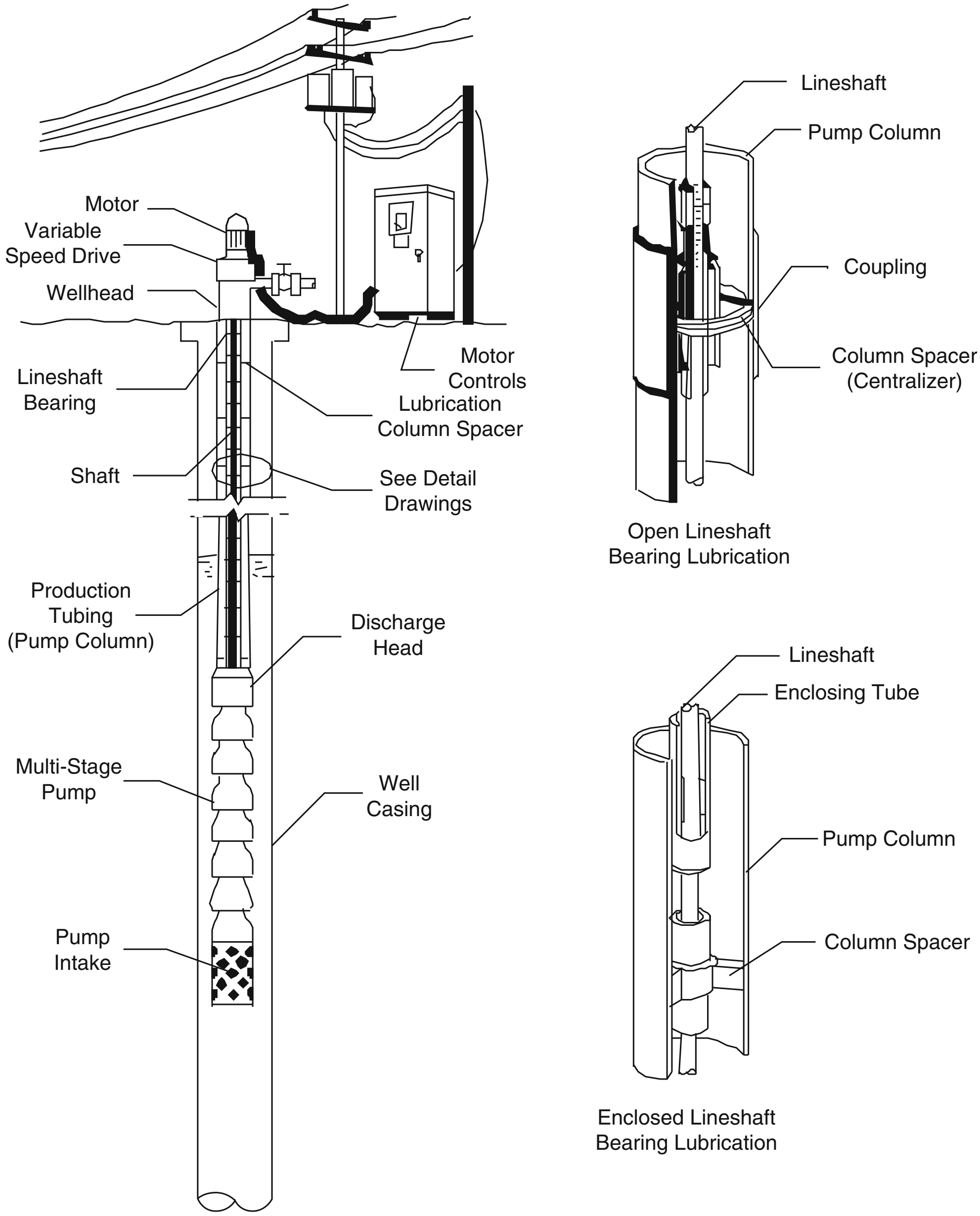
Both types of downhole pumps have been used for many years for cold water pumping and more recently in geothermal wells (lineshafts have been used on the Oregon Institute of Technology campus in 89°C water for almost 60 years). If a lineshaft pump is used, special allowances must be made for the thermal expansion of various components and for oil lubrication of the bearings [27]. The lineshaft pumps are preferred over the submersible pump in conventional geothermal applications for two main reasons: the lineshaft pump cost less, and it has a proven track record. However, for setting depths exceeding about 250 m, a submersible pump is required.

Piping

The fluid state in transmission lines of direct-use projects can be liquid water, steam vapor, or a two-phase mixture. These pipelines carry fluids from the wellhead to either a site of application or a steam-water separator. Thermal expansion of metallic pipelines heated rapidly from ambient to geothermal fluid temperatures (which could vary from 50°C to 200°C) causes stress that must be accommodated by careful engineering design.

The cost of transmission lines and the distribution networks in direct-use projects is significant. This is especially true when the geothermal resource is located at great distance from the main load center; however, transmission distances of up to 60 km have proven economical for hot water (i.e., the Akranes project in Iceland [28], where asbestos cement covered with earth has been successful (see Fig. 20 later).

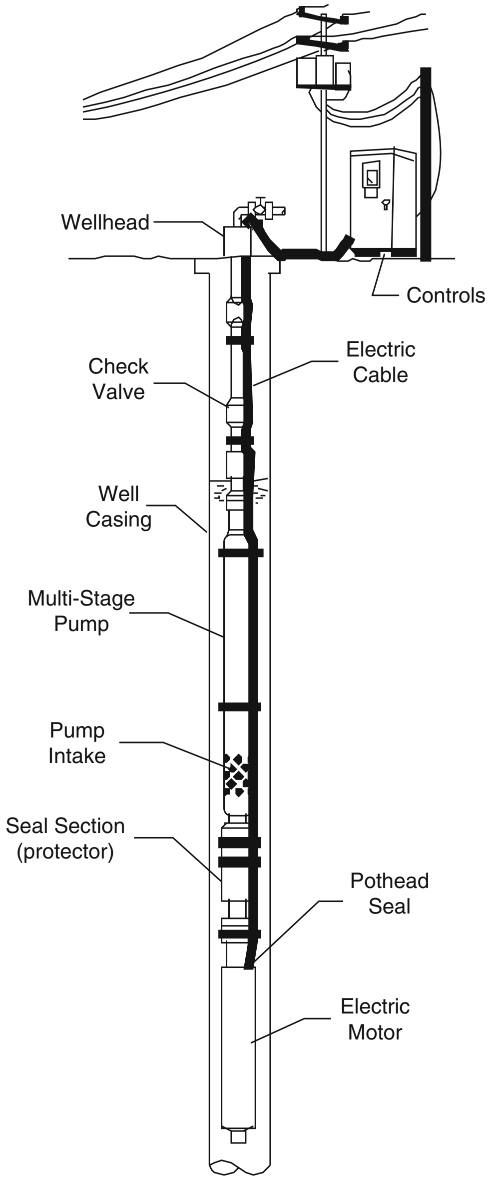
Carbon steel is now the most widely used material for geothermal transmission lines and distribution networks, especially if the fluid temperature is over 100°C. Other common types of piping material are fiberglass reinforced plastic (FRP) and asbestos cement (AC). The latter material, used widely in the past, cannot be used in many systems today due to environmental concerns; thus, it is no longer available in many locations. Polyvinyl chloride (PVC) piping is often used for the distribution network, and for uninsulated waste disposal lines where temperatures are well below 100°C. Cross-linked polyethylene pipe (PEX) have become popular in recent years as they can tolerate temperatures up to 100°C and still take pressures up to 550 kPa. However, PEX pipe is currently only available in sizes less than 5 cm in diameter. Conventional steel piping requires expansion provisions, either bellows arrangements or by loops. A typical piping installation would have fixed points and expansion points about every 100 m. In addition, the piping would have to be placed on rollers or slip plates between points. When hot water metallic pipelines are buried, they can be subjected to external corrosion from groundwater and electrolysis. They must be protected by coatings and wrappings. Concrete tunnels or trenches have been used to protect steel pipes in many geothermal district heating systems. Although expensive (generally over US $300 per meter of length), tunnels and trenches have the advantage of easing



Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 17
Lineshaft pump

future expansion, providing access for maintenance and a corridor for other utilities such as domestic water, waste water, electrical cables, phone lines, etc.

Supply and distribution systems can consist of either a single-pipe or a two-pipe system. The single-pipe is a once-through system where the fluid is disposed of after use. This distribution system is generally preferred when the geothermal energy is abundant and the water is pure enough to be circulated through the distribution system. In a two-pipe system, the fluid is recirculated so the fluid and residual heat are conserved. A two-pipe system must be used when



Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 18
Submersible pump

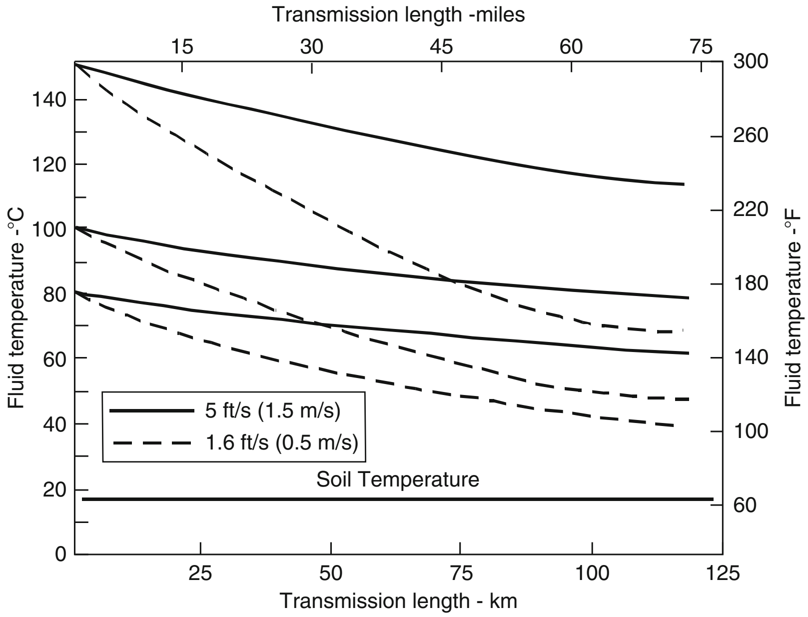
mixing of spent fluids is called for, and when the spent cold fluids need to be injected into the reservoir. Two-pipe distribution systems cost typically 20–30% more than single-piped systems.

The quantity of thermal insulation of transmission lines and distribution networks will depend on many factors. In addition to minimize the heat loss of the fluid, the insulation must be waterproof and water tight. Moisture can destroy the value of any thermal insulation and cause rapid external corrosion of metallic pipe. Above ground and overhead pipeline, installations can be considered in special cases. Considerable insulation is achieved by burying hot water pipelines. For example, burying bare steel pipe results in a reduction in heat loss of about one third as compared to aboveground in still air. If the soil around the buried pipe can be kept dry, then the insulation value can be retained. Carbon steel piping can be insulated with polyurethane foam, rock wool, or fiberglass. Belowground, such pipes should be protected with polyvinyl chloride (PVC) jacket; aboveground, aluminium can be used. Generally, 2.5–10 cm of insulation is adequate. In two-pipe systems, the supply and return lines are usually insulated; whereas, in single-pipe systems, only the supply line is insulated.

At flowing conditions, the temperature loss in insulated pipelines is in the range of 0.1–1.0°C/km, and in uninsulated lines, the loss is 2–5°C/km (in the approximate range of 5–15 L/s flow for 15-cm diameter pipe) [29]. It is less for larger diameter pipes. For example, less than 2°C loss is experienced in the new aboveground 29 km long and 80 and 90 cm diameter line (with 10 cm of rock wool insulation) from Nesjavellir to Reykjavik in Iceland. The flow rate is around 560 L/s and takes 7 h to cover the distance. Uninsulated pipe costs about half of insulated pipe, and thus is used where temperature loss is not critical. Pipe material does not have a significant effect on heat loss; however, the flow rate does. At low flow rates (off peak), the heat loss is higher than as greater flows. Figure 18 shows fluid temperatures, as a function of distance, in a 45-cm diameter pipeline, insulated with 50 cm of urethane foam.

Several examples of aboveground and buried pipeline installations are shown in Fig. 20.

Steel piping is shown in most case, but FRP or PVC can be used in low-temperature applications. Aboveground pipelines have been used extensively in Iceland, where excavation in lava rock is expensive and difficult; however, in the USA, below ground installations are more common to protect the line from vandalism and to eliminate traffic barriers. A detailed discussion of these various installations can be found in Gudmundsson and Lund [2].



Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 19
Temperature drop in hot water transmission line

Heat Exchangers

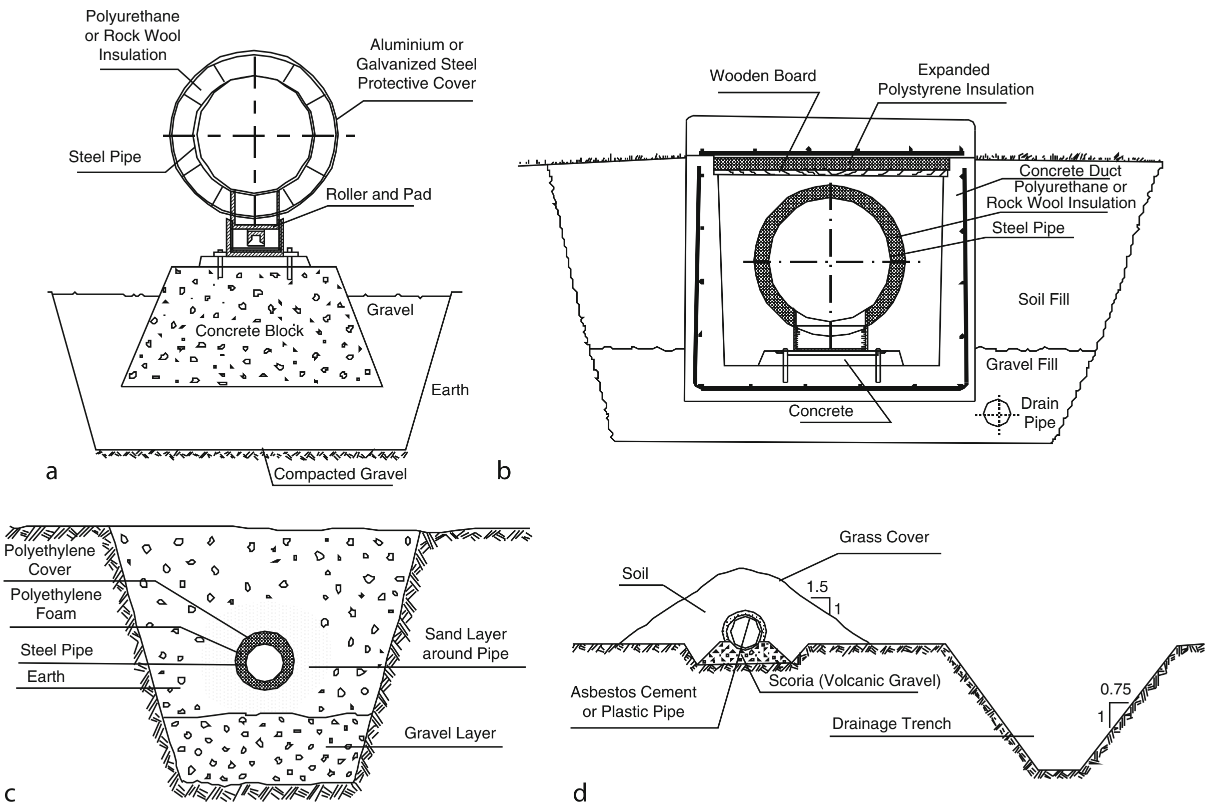
The principal heat exchangers used in geothermal systems are the plate, shell-and-tube, and downhole types. The plate heat exchanger consists of a series of plates with gaskets held in a frame by clamping rods (Fig. 21). The countercurrent flow and high turbulence achieved in plate heat exchangers provide for efficient thermal exchange in a small volume. In addition, they have the advantage when compared to shell-and-tube exchangers, of occupying less space, can easily be expanded when addition load is added, and cost 40% less. The plates are usually made of stainless steel; although, titanium is used when the fluids are especially corrosive. Plate heat exchangers are commonly used in geothermal heating situations worldwide.

Shell-and-tube heat exchangers may be used for geothermal applications but are less popular due to problems with fouling, greater approach temperature (difference between incoming and outgoing fluid temperature), and the larger size.

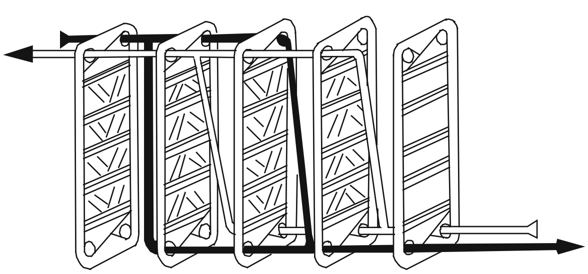
Downhole heat exchangers eliminate the problem of disposal of geothermal fluid since only heat is taken from the well. However, their use is limited to small heating loads such as the heating of individual homes, a small apartment house or business. The exchanger consists of a system of pipes or tubes suspended in the well through which secondary water is pumped or allowed to circulate by natural convection (Fig. 22). In order to obtain maximum output, the well must be designed to have an open annulus between the wellbore and casing, and perforations above and below the heat exchanger surface. Natural convection circulates the water down inside the casing through the lower perforations, up in the annulus, and back inside the casing through the upper perforations [30, 31]. The use of a separate pipe or promoter has proven successful in older wells in New Zealand to increase the vertical circulation [32].

Heat Pumps

At the present time, ground-coupled and groundwater (often called ground-source or geothermal) heat pump systems are being installed in great numbers in the USA, Canada, Switzerland, Sweden, Austria, and Germany [4, 33]. Groundwater aquifers and soil temperatures in the range of 5–30°C are being used in these systems. Geothermal heat pumps (GHP) utilize groundwater in wells (open loop) or by direct ground coupling



Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 20
Examples of above and below ground pipelines: (**a**) aboveground pipeline with sheet metal cover, (**b**) steel pipe in concrete tunnels, (**c**) steel pipe with polyurethane insulation and polyethylene cover, and (**d**) asbestos cement pipe with earth and grass cover

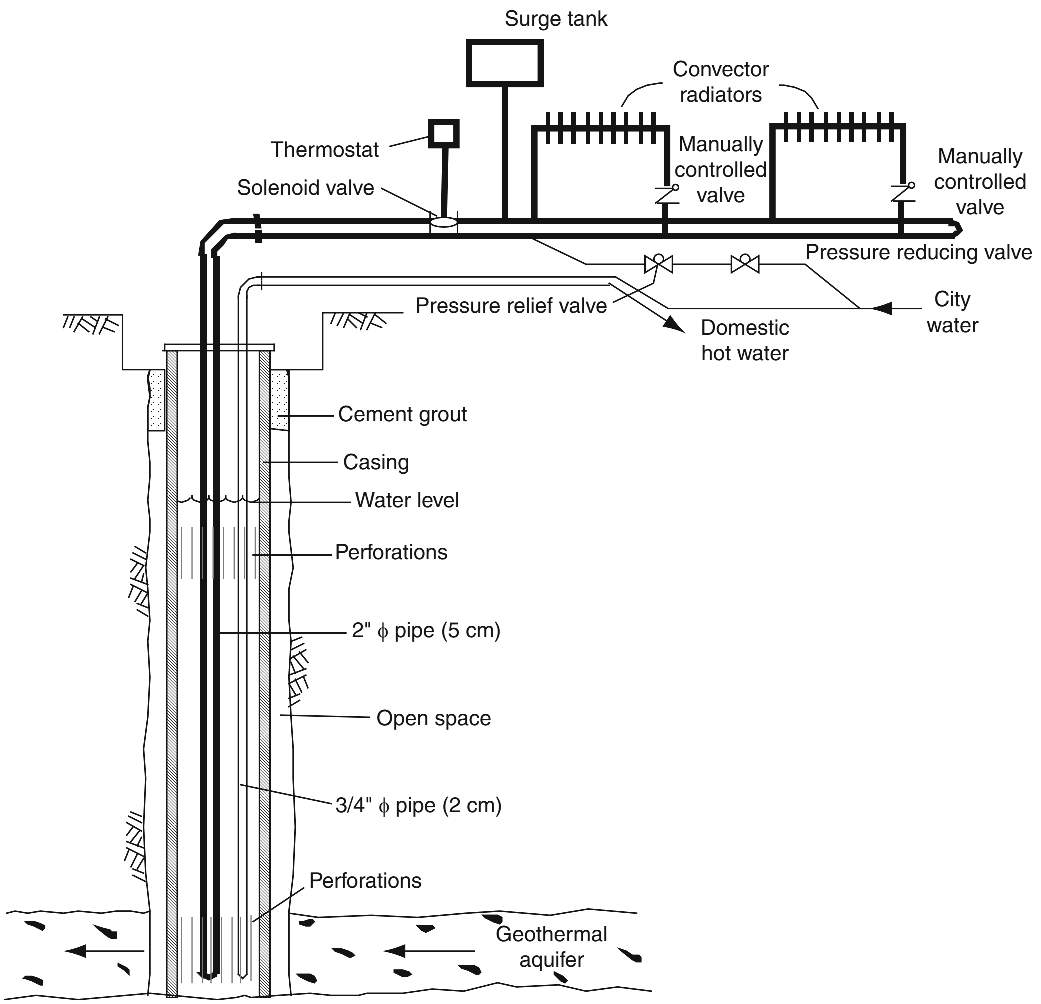


Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 21
Plate heat exchanger

(closed loop) with vertical or horizontal heat exchangers. Just about every state in the USA, especially in the midwestern and eastern states are utilizing these systems in part subsidized by public and private utilities. It is estimated that almost 3.0 million units (12 kW) are installed in 43 countries worldwide, with most in Europe, Canada and the USA. Annual growth rates are around 17%, the fastest of all the direct-use applications.

Like refrigerators, heat pumps operate on the basic principle that fluid absorbs heat when it evaporates into a gas, and likewise gives off heat when it condenses back into a liquid. A geothermal heat pump system can be used for both heating and cooling. The types of heat pumps that are adaptable to geothermal energy are the water-to-air and the water-to-water. Heat pumps are available with heating capacities of less than 3 kW to over 1,500 kW.

GHPs use the relatively constant temperature of the earth to provide heating, cooling and domestic hot water for homes, schools, government and commercial buildings. A small amount of electricity input is

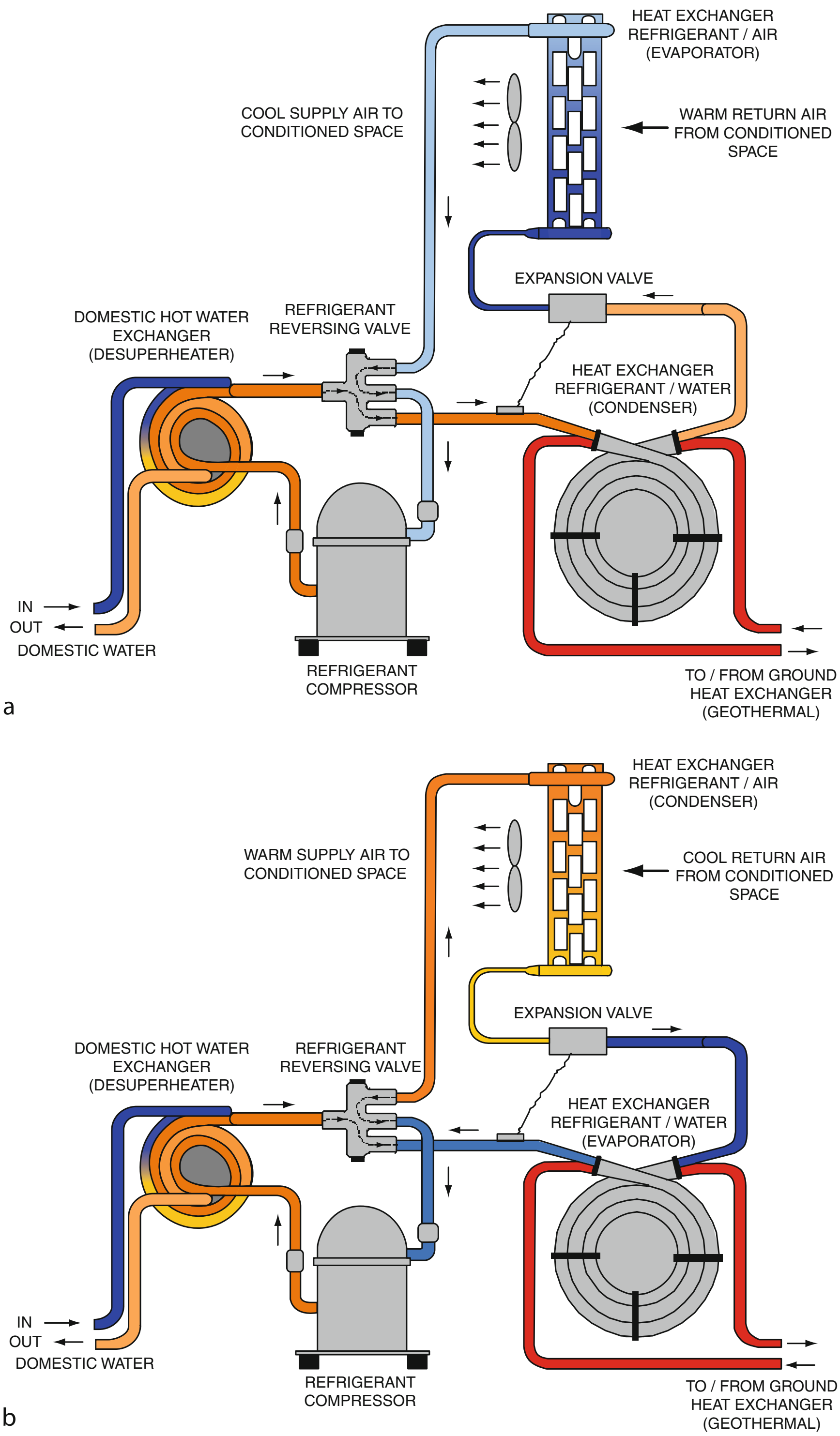


Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 22
Downhole heat exchanger (typical of Klamath Falls, Oregon)

required to run a compressor; however, the energy output is in the order of four times this input. These "machines" cause heat to flow "uphill" from a lower to higher temperature location – really nothing more than a refrigeration unit that can be reversed. "Pump" is used to described the work done, and the temperature difference called the "lift" – the greater the lift, the greater the energy input. The technology is not new, as Lord Kelvin developed the concept in 1852, which was then modified as a GHP by Robert Webber in the 1940s. They gained commercial popularity in the 1960s and 1970s. See Fig. 23 for diagrams of typical GHP operation.

GHPs come in two basic configurations: ground-coupled (closed loop) which are installed horizontally, and vertically and groundwater (open loop) systems, which are installed in wells and lakes. The type chosen depends upon the soil and rock type at the installation, the land available and/or if a water well can be drilled economically or is already on site. As shown in Fig. 23, a desuperheater can be provided to use reject heat in the summer and some input heat in the winter for the domestic hot water heating.

In the ground-coupled system, a closed loop of pipe, placed either horizontally (1–2 m deep) or



Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 23
(**a**) GHP in the cooling cycle (From Oklahoma State University). (**b**) GHP in the heating cycle (From Oklahoma State University)

vertically (50–100 m deep) is placed in the ground and a water-antifreeze solution is circulated through the plastic pipes (high density polyethylene) to either collect heat from the ground in the winter or reject heat to the ground in the summer [34]. The open loop system uses ground water or lake water directly in the heat exchanger and then discharges it into another well, into a stream or lake, or on the ground (say for irrigation), depending upon local laws.

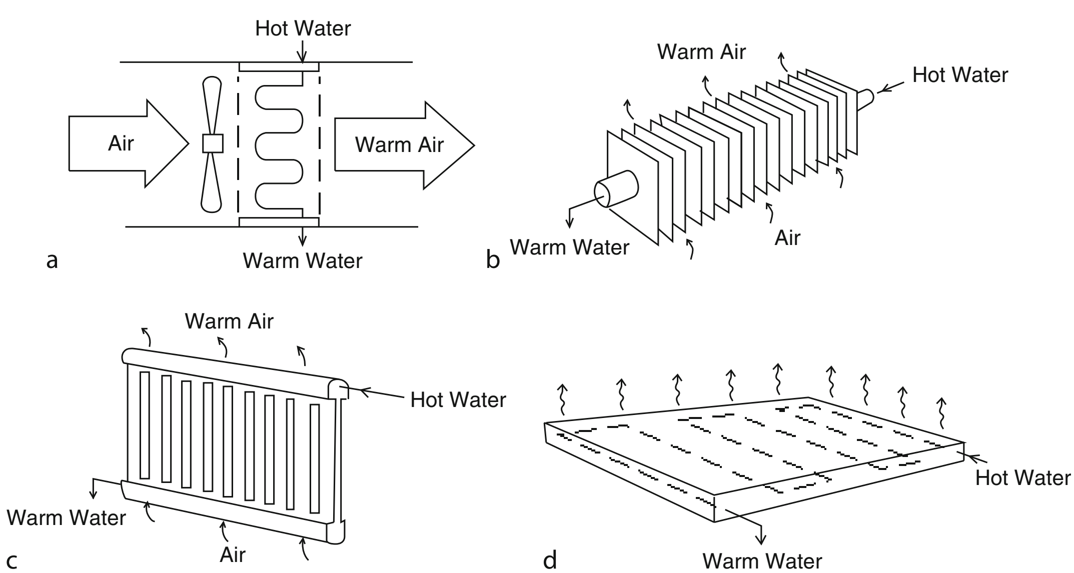
The efficiency of GHP units are described by the Coefficient of Performance (COP) in the heating mode and the Energy Efficiency Ratio (EER) in the cooling mode (COP_h and COP_c, respectively, in Europe) which is the ratio of the output thermal energy divided by the input energy (electricity for the compressor) and varies from 3 to 6 with present equipment (the higher the number the better the efficiency). Thus a COP of 4 would indicate that the unit produced four units of heating energy for every unit of electrical energy input. In comparison, an air-source heat pump has a COP of around 2 and is dependent upon backup electrical energy to meet peak heating and cooling requirements. In Europe, this ratio is sometimes referred to as the "Seasonal Performance Factor" ("Jahresarbeitszahl" in German) and is the average COP over the heating and cooling season, respectively, and takes into account system properties (see Curtis et al. [33], Lund et al. [35], and Kavanauagh and Rafferty [36] for more background material).

Convectors

Heating of individual rooms and buildings is achieved by passing geothermal water (or a heated secondary fluid) through heat convectors (or emitters) located in each room [26]. The method is similar to that used in conventional space heating systems. Three major types of heat convectors are used for space heating: (1) forced air, (2) natural air flow using hot water or finned tube radiators, and (3) radiant panels (Fig. 24). All these can be adapted directly to geothermal energy or converted by retrofitting existing systems.

Refrigeration

Cooling can be accomplished from geothermal energy using lithium bromide and ammonia absorption refrigeration systems [26, 37]. The lithium bromide system is the most common because if uses water as the refrigerant. However, it is limited to cooling above the freezing



Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 24
Convectors: (**a**) forced air, (**b**) material convection (finned tube), (**c**) natural convection (radiator), and (**d**) floor radiant panel

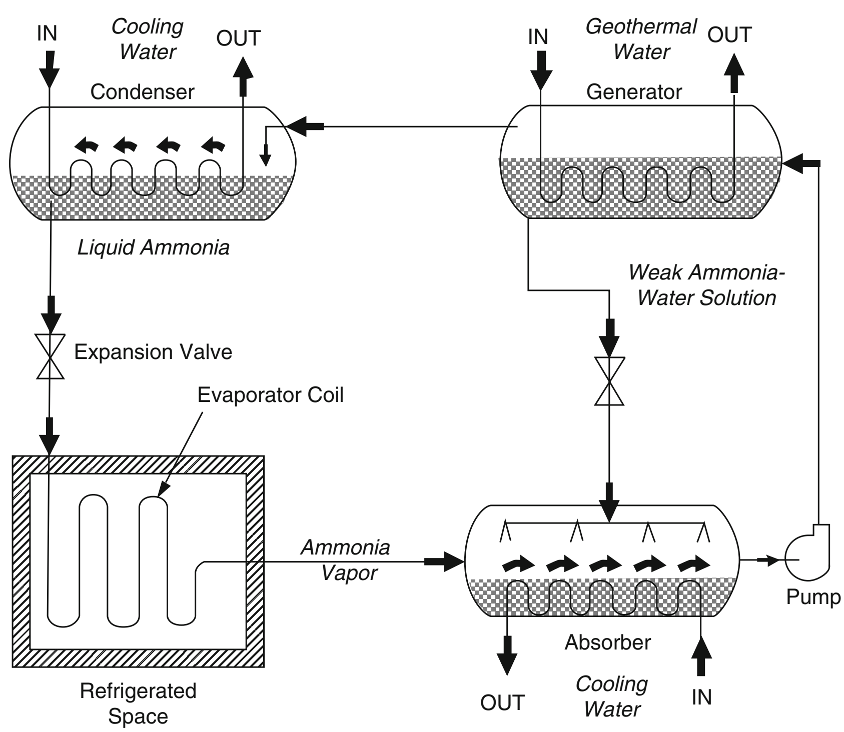
point of water. The major application of lithium bromide units is for the supply of chilled water for space and process cooling. They may be either one- or two-stage units. The two-stage units require higher temperatures (about 160°C); but, they also have high efficiency. The single-stage units can be driven with hot water at temperatures as low as 77°C (such as at Oregon Institute of Technology – see Fig. 5). The lower the temperature of the geothermal water, the higher the flow rate required and the lower the efficiency. Generally, a condensing (cooling) tower is required, which will add to the cost and space requirements.

For geothermally driven refrigeration below the freezing point of water, the ammonia absorption system must be considered. However, these systems are normally applied in very large capacities and have seen limited use. For the lower temperature refrigeration, the driving temperature must be at or above about 120°C for a reasonable performance. Figure 25 illustrates how the geothermal absorption process works.

Economic Considerations

Geothermal projects require a relatively large initial capital investment, with small annual operating costs thereafter. Thus, a district heating project, including production wells, pipelines, heat exchangers, and injection wells, may cost several million dollars. By contrast, the initial investment in a fossil fuel system includes only the cost of a central boiler and distribution lines. The annual operation and maintenance costs for the two systems are similar, except that the fossil fuel system may continue to pay for fuel at an ever-increasing rate while the cost of the geothermal fuel is stable. The two systems, one with a high initial capital cost and the other with high annual costs, must be compared. Table 3 is an attempt to quantify the cost of various direct-use types based on experiences in the USA.

Geothermal resources fill many needs: power generation, space heating, greenhouse heating, industrial processing, and bathing to name a few. Considered individually, however, some of the uses may not



Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 25
Geothermal absorption refrigeration cycle

Geothermal Resources Worldwide, Direct Heat Utilization of. Table 3 Average costs of direct-use systems in the USA for 2005

Application	Capital ($/kW)	Cost/year ($/kW/year)	O$M ($/kW/year)	Total ($/kW/year)	Capacity factor	Unit cost (cents/kWh)
Residential space heating[a]	800	71.1	7.1	78.2	0.31	3.08
Comm./inst. Space heating[a]	500	44.4	4.4	48.8	0.25	2.23
District heating	650	57.7	5.8	63.5	0.33	2.42
Greenhouse heating	250	22.2	2.2	24.4	0.26	1.11
Aquaculture pond heating	200	17.8	1.8	19.6	0.69	0.32
Geothermal heat pumps[b]	850	75.5	7.6	83.1	0.13	6.78

Based on 30-year life at 8.0% interest and O&M at 10% of capital cost

The above costs includes a shallow well (<300 m) and no retrofit costs; however, cost can vary by as much as 100% depending on the local geology, hydrology, building construction, and infrastructure

[a]Assumes one production and one injection well for a single building

[b]Heat pump figures are considered only for the heating mode and the capacity factor is a nationwide average

promise an attractive return on investment because of the high initial capital cost. Thus, the usage of a geothermal fluid may have to be considered several times to maximize benefits. This multistage utilization, where lower and lower water temperatures are used in successive steps, is called cascading or waste heat utilization. A simple form of cascading employs waste heat from a power plant for direct-use projects referred to as a combined heat and power application (Fig. 19) [38].

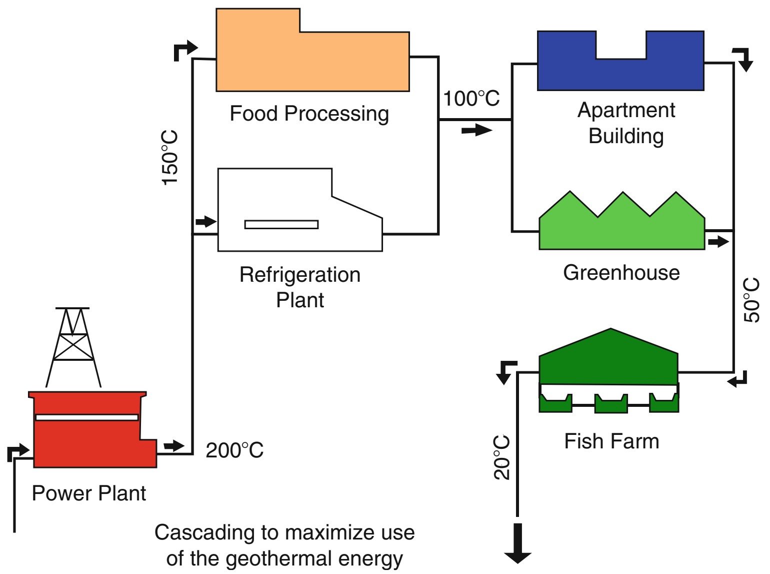
Geothermal cascading has been proposed and successfully attempted on a limited scale throughout the world. A generalized example is shown in Fig. 26. In Rotorua, New Zealand, for example, after geothermal water and steam heat a home, the owner will often use the waste heat for a backyard swimming pool and steam cooker. At the Otake geothermal power plant in Japan, about 165 t/h of hot water flows to downstream communities for space heating, greenhouses, baths, and cooking. In Sapporo, Hokkaido, Japan, the waste water from the pavement snow melting system is retained at 65°C and reused for bathing. An example of combined heat and power installation using geothermal waters down to 100°C are installed in Germany and Austria. At Neustadt Glewe in northern Germany, 98°C water from a 2,300 m-deep well at 1,700 L/s provides 11 MW (thermal) for a district heating network and 210 kW (electric) from a binary power plant meeting the electricity demands for 500 households [39].

Energy Savings

Geothermal, a domestic source of energy, could replace other forms of energy, especially fossil fuels. For many countries, geothermal energy could lead to a reduction in their dependence on imported fuels, and for all countries, it means the elimination of pollutants such as particulates and greenhouse gases. An attempt is made here to quantify the fossil fuel savings, using a 0.35 efficiency factor if the competing energy is used to generate electricity and 0.70 if it is used directly to produce heat, such as in a furnace.

Using the 438,071 TJ/year of energy consumed in direct geothermal applications in 2010 (Table 2), and estimating that a barrel of fuel oil contains 6.06×10^9 J, and that the fuel is used to produce replacement electricity, the savings would be 206.5 million barrels of oil or 31.0 million tons of oil annually. If the oil were used directly to produce energy by burning, then these savings would be halved. The actual savings are most likely somewhere in between these two values.

The carbon savings would be 63 million tons, and the CO_2 emission savings would be 99 million tons based on using oil to produce electricity. If the savings in the cooling mode of geothermal heat pumps is



Geothermal Resources Worldwide, Direct Heat Utilization of. Figure 26
An example of cascading

considered, then this is equivalent to an additional annual savings of 101.3 million barrels (15.2 million tons) of fuel oil or 19.2 million tons of carbon pollution from burning fuel oil (see Lund et al. [4] for more details). The total of 308 million barrels (45.2 million tons) corresponds to almost 3 days of worldwide oil consumption.

There appears to be a large potential for the development of low-to-moderate enthalpy geothermal direct-use across the world which is not currently being exploited due to financial constraints and the low price of competing energy sources. Given the right environment, and as gas and oil supplies dwindles and with recent price increases, the use of geothermal energy will provide a competitive, viable, and economic alternative source of renewable energy.

Future Directions

Future development will most likely occur under the following conditions:

1. Collocated resource and uses (within 10 km apart)
2. Sites with high heat and cooling load density (>36 MWt/km^2)
3. Food and grain dehydration (especially in tropical countries where spoilage is common)
4. Greenhouses in colder climates
5. Aquaculture to optimize growth – even in warm climates
6. Ground-coupled and groundwater heat pump installation (both for heating and cooling)
7. Combined heat and power installation using low-temperature resources in a binary power plant

Direct use has grown at an almost 9% annual rate over the past 10 years, and geothermal heat pumps alone has grown at a 17% annual rate over the same period [4]. The recent rise in the cost of oil and natural gas has made geothermal energy more competitive, and along with the environmental benefits associated with this renewable energy, development of this natural "heat from the earth" should accelerate in the future. At the 9% annual growth rate, the geothermal energy use should more than double over the next 10 years.

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Geothermal Resources, Drilling for

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Article Outline

Glossary

Barrel An extremely common unit of volume in the drilling industry, equal to 42 US gallons or 178 l.

BHA (bottom-hole assembly) The assembly of heavy drilling tools at the bottom of the drill string; normally includes bit, reamers, stabilizers, drill collars, heavy-weight drill pipe, jars, and other miscellaneous tools.

Blow out Uncontrolled flow of fluids from a wellhead or wellbore.

BOP (blow-out preventer) One or more devices used to seal the well at the wellhead, preventing uncontrolled escape of gases, liquids, or steam; usually includes annular preventer (an inflatable bladder that seals around drill string or irregularly shaped tools) and rams (pipe rams or blind rams: pipe rams seal around the drill pipe if it is in the hole, blind rams seal against each other if the pipe is not in the hole).

Dewar A double-walled container or heat shield, similar to a vacuum flask, which insulates a piece of equipment from high temperature.

Directional drilling Deliberately drilling on a controlled non-vertical trajectory, usually done to improve productivity.

Drill collars Heavy-walled sections at the bottom of the drill string; provide stiffness, vibration control, and most of the weight on the bit.

Fish Any part of the drill string, or other tools, accidentally left in the hole; also, *fishing* – trying to retrieve a fish.

H_2S (hydrogen sulfide) A poisonous gas sometimes found in geothermal drilling.

LCM (lost-circulation material) Any material used to plug formation fractures to avoid loss of drilling fluid.

Stand More than one joint of drill pipe screwed together; when tripping, pipe is handled in stands to avoid making and breaking every connection – for a coring rig, a typical stand is four 3 m joints (12 m), but for a large rotary rig, a stand is three 10 m joints (30 m).

Sub Generic name for part of the drill string; for example, instrumentation sub carries instruments for navigation or logging; crossover sub allows different threads to be connected; bent sub forms a slight angle between the axis of the drill string and the axis of a downhole motor, allowing directional drilling.

Trip Any event of pulling the drill string out of the hole and returning it.

Twist-off Failure mode in which some element of the drill string parts, leaving at least one portion of the drill string in the hole.

Under-pressured Describes the pore pressure of in situ fluids during drilling as less than the static head of a water column to the same depth in the wellbore.

Washout A hole or leak in the drill string; often caused by fatigue failure, but very dangerous because the flow of high-pressure drilling fluid through the leak will quickly enlarge it to the point of parting the drill string.

Definition of the Subject

The word "geothermal" comes from the combination of the Greek words gê, meaning Earth, and thérm, meaning heat. Quite literally, geothermal energy is the heat of

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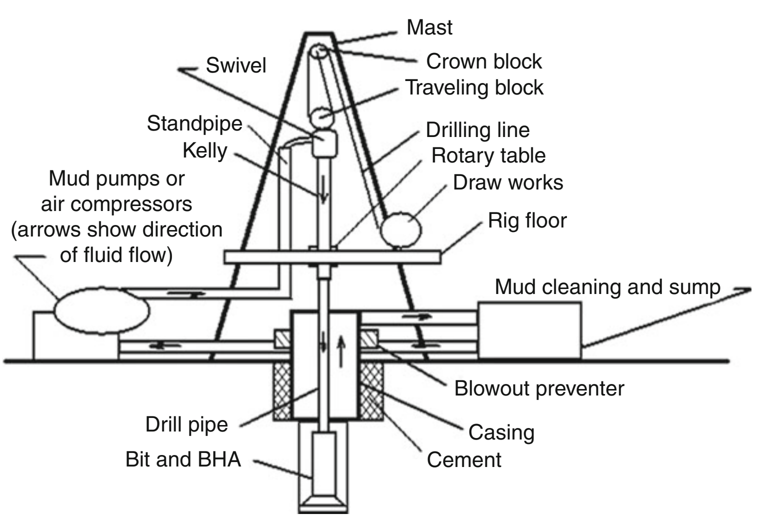
the Earth. Geothermal resources are concentrations of the Earth's heat that can be extracted economically for some useful purposes. All existing applications of geothermal energy use a circulating fluid to carry the heat from depth to its use at the surface, and this means that holes must be drilled for access to or introduction of these fluids. Drilling, therefore, is a major component of any geothermal project's development.

This entry describes the overall process of drilling, with emphasis on the ways in which geothermal drilling differs from other kinds of drilling, such as that for oil and gas. The entry also focuses on the drilling of relatively large-diameter, high-temperature holes, such as those most often used to supply electrical generating plants, and specifically does not address the following topics: low-temperature drilling for direct-use application, well maintenance and workover, or drilling for geothermal heat-pump installations. The entry should by no means be considered a set of instructions on how to drill a geothermal well, but is intended to illuminate some of the major decisions that will be necessary during that process.

Introduction

Geothermal energy is a growing enterprise. Worldwide electricity production increased from 6,833 MWe (megawatts electric) in 1995 to 9,966 MWe in 2008, and direct use in 2005 displaced more than thirty million barrels of oil [1]. In spite of this growth, geothermal drilling activity is minuscule compared to oil and gas – fewer than 100 geothermal wells were drilled in the USA during 2008, while the total for oil and gas exceeded 50,000 [2]. This means that few service companies or drilling contractors can sustain their business solely within the geothermal industry, and it also leads to a lack of research into tools or techniques specifically aimed at geothermal drilling. A substantial number of deep gas wells, however, now have producing horizons with geothermal-like temperatures (~175°C), so this has brought new interest into high-temperature drilling.

Before describing the aspects that make geothermal drilling unique, however, a brief summary of the fundamental process will be useful. The process of drilling, rather than digging, holes in the ground has been under development for thousands of years, but the techniques we now know as "conventional rotary drilling" began to be developed around the end of the nineteenth century. This technology, with only minor variations, is ubiquitous in the oil, gas, geothermal, water well, and mining industries. There is an extensive literature on the principles and practices of this kind of drilling [3], and a baseline system – a tall, steel derrick supporting a string of pipe which turns a bit to drill the hole – is at least superficially familiar to most readers (Fig. 1).



Geothermal Resources, Drilling for. Figure 1
Drill rig diagram

Basic Drilling Functions

Any drilling system must perform six basic functions:

1. Transmit energy from the surface to the rock face
2. Reduce rock from its more-or-less monolithic state
3. Remove the reduced rock from the wellbore
4. Maintain control of any pressures encountered in the wellbore
5. Keep the hole open, stable at some minimum diameter, and on the desired trajectory while drilling
6. Preserve and control the well for some indefinite, but relatively long, time

Each of these functions is described in more detail, with the same numbering reference as above. In the baseline system, all of the equipment necessary for the drilling operation is organized around the derrick, or mast. This is a steel tower, ranging from 16 m to 50 m in height, which supports the drill pipe with the bit and all the other downhole equipment, and which provides a platform for much of the other equipment necessary to drill the hole. Every rig, except for the smallest ones, has a floor just above ground level where most activity required to operate the rig takes place. The driller, who has minute-by-minute control of the rig's operation, has a control console here and most equipment handling (adding a new piece of drill pipe, making and breaking drill string connections, changing bits, etc.) takes place on the floor. In smaller rigs, the mast and the floor are a unit and are simply raised into position in preparation for drilling. Because of larger hole sizes, geothermal wells usually need bigger rigs, which may require 50–60 large truck loads for transportation. These rigs are usually assembled at the drill site, a job which may take several days, even in accessible locations on land.

1. To make the hole, energy must be transmitted from the surface to the rock face at the end of the wellbore. Power supply for drilling has evolved from the early days of steam-driven, mechanically coupled rigs to the current standard of diesel-electric drive. In this configuration, two to four diesel engines (up to 1,500 kW each) drive electric generators, which supply power to individual electric motors driving the rotary table, drawworks, mud pumps, and other equipment. The rotary table is a mechanism, usually inset into the rig floor, which turns the drill string to break rock and advance the hole. (A "drill string" comprises the drill pipe plus the bottom-hole assembly, or BHA. The BHA includes drill collars, stabilizers, bit, and any other specialized tools below the drill pipe.) Torque is applied to the kelly, which is attached to the top of the drill string. The kelly is a section of pipe with a square or hexagonal outside cross section that engages a matching bushing in the rotary table. This bushing lets the rotary table continuously turn the kelly and drill string while they slide downward as the hole advances.

The upper end of the kelly is attached to a "swivel," which is a rotating pressure fitting that allows the drilling fluid to flow from the mud pumps, up the standpipe, through the kelly hose, into the swivel, and finally down the drill pipe as it rotates. The swivel is carried by the hook on the traveling block and it suspends most of the weight of the drill string while drilling.

Moving the drill string into and out of the hole is called tripping. Trips are usually required when the bit or some other piece of downhole equipment must be replaced, or because of some activity such as logging, testing, or running casing. Clearly, trips take longer as the hole grows deeper. Raising or lowering the drill string for a trip is done by the drawworks, which is a large winch. The drawworks reels in or pays out a wire rope (drilling line) that passes over the crown block at the top of the rig's mast and then down to the traveling block which carries the hook, which in turn suspends the drill string or casing. Depending on what mechanical advantage is required, the drilling line is reeved several times between the crown and traveling blocks, as in a block and tackle.

2. Attached to the bottom of the drill string, the bit rotates to break (reduce) the rock from its more-or-less monolithic state into small fragments (usually called "cuttings") and to advance the hole. A tremendous variety of bits is available, and some of the important types are discussed in more detail in the section Drill Bits and Bottom-Hole Assemblies.

3. Once the rock has been reduced to chips and fines, it must be removed from the hole bottom to expose fresh rock surface and to avoid wasting energy by re-grinding these same cuttings. This cleaning is done by a stream of fluid that circulates down the drill pipe, passes through ports (called "jets") in the bit, and returns up the annulus between the wellbore

wall and the outside of the drill string, carrying the rock cuttings back to the surface. This fluid is sometimes a gas (air, nitrogen, and natural gas), but is most often a liquid, universally known as "mud" from its origin as a mixture of water and clay.

Air drilling, in which the hole is cleaned by a compressor-driven airstream, generally makes hole faster than mud drilling, but suffers severe issues with well control, hole stability, drill-pipe erosion, and difficulty with handling water influx. Mud drilling uses pumps to circulate the liquid, which not only carries cuttings but stabilizes the wellbore and lubricates the bit and drill string. When mud returns to the surface, it is cleaned to remove most of the rock cuttings and is then recirculated. Pumping mud while drilling, at typical flow rates of 12 to 50 l/s, with pressures up to 20 MPa, can represent more than 75% of the rig's total power consumption. Requirements for drilling fluids and the circulating system are described in more detail in the Section Drilling Fluids.

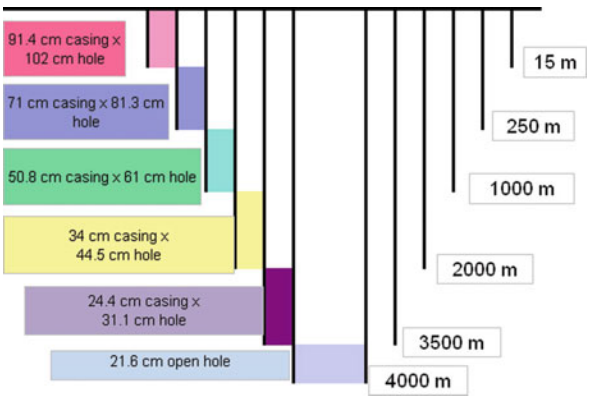
4. During drilling, the personnel and equipment must be protected against unexpected pressure surges in the wellbore. In oil and gas drilling, these surges can come from hydrocarbon fluids trapped under impermeable rock which holds them at pressures higher than the static head of the fluid column in the wellbore, and in geothermal operations the surges come from hot formations which heat the pore or wellbore fluids above the saturation temperature at the static wellbore pressure. In either case, the first line of control is the weight of the fluid column in the wellbore. With a gas column, this weight is negligible, but with mud the liquid density will range from slightly greater than water (specific gravity $\sim$ 1.05) to almost three times that. In addition to the clays and additives that raise the viscosity of the mud to improve hole cleaning, weighting materials such as barite are often added to increase the mud's density and enable it to control higher downhole pressures. If a pressure surge cannot immediately be controlled with fluid weight, the wellbore can be mechanically sealed at the surface with BOPs, or blow-out preventers. See the Section Well Control for more detailed information on blow-out prevention equipment and well control.

5. Hole stability can be a problem after drilling through some kinds of rock for several reasons: the formation may tend to swell (because it absorbs water) or squeeze (extrude into the wellbore because of overburden pressure), both of which reduce the hole diameter; or chunks of the wellbore wall may cave or slough into the hole. These phenomena can cause problems ranging from minor (the necessity to clean out debris or to ream part of the hole) to major (stuck drill string). With gas drilling, there is no liquid to cause swelling, but there is no fluid pressure to counteract squeezing. With mud, these problems can often be eliminated or mitigated by the pressure of the fluid column or by the mud's chemical composition.

Controlling the hole's trajectory has two major components: keeping it either straight or, in the case of directional drilling, deviating along a relatively smooth curve; and making sure that the hole is advancing in the proper direction. Keeping the hole straight or smoothly curved is necessary to allow the casing to be run easily; getting a string of casing stuck during its deployment can be a serious and expensive problem. If the hole is being directionally drilled, the two principal aspects of hole trajectory are inclination and azimuth. Vertical holes depend mostly on the pendulum effect of gravity to keep the drill string pointed downward, but sometimes the combination of BHA design and formation properties will drive the hole away from verticality.

If the hole trajectory must be changed, either to correct unwanted deviation or to steer it toward a specific target, it is necessary to force the hole into the correct trajectory with directional drilling. Directional drilling is extensively used in the oil and gas industry to increase productivity by keeping the hole in hydrocarbon-bearing strata, and similarly in geothermal reservoirs to intersect more productive fractures. Directional drilling is a complex topic [4] and there are a number of techniques available for performing it, but a complete discussion is far beyond the scope of this entry. One aspect that is relevant to geothermal drilling is that the drilling motors and electronic steering-survey tools are susceptible to high temperature, so the hole trajectory is usually set in the upper, cooler interval of the hole and then efforts are just to keep it straight from there.

6. Once the hole is drilled to the target depth, it must be kept open for testing or production. This is conventionally done by putting steel pipe, or casing, into the hole and cementing it in place. Casing is not done all at once, at the end of drilling, but is placed



Geothermal Resources, Drilling for. Figure 2
Diagram of typical casing program

sequentially in the hole as it reaches increasingly greater depths. As each casing string is placed and cemented, the hole interval below that string must be smaller than the one above, since the new drill bit must pass through the casing just set. The completed hole, then, will usually have two to four concentric strings of casing cemented in place with an open-hole section at the bottom for production of the desired fluids (Fig. 2).

To complete any given interval of the well, casing (which is several centimeters smaller than the hole diameter at that point) is lowered almost to the bottom of the hole; then cement is pumped down the inside of the casing and displaced with mud up the annulus between the casing and the wellbore wall. Because large volumes of cement must be pumped quickly, and at high pressure because of the density difference between the mud and cement, specialized cementing equipment is used for this job. It is not uncommon for the cost of casing and cement to approach half the total well cost.

Unique Aspects of Geothermal Drilling

Compared to the sedimentary formations of most oil and gas reservoirs, geothermal formations are, by definition, hot (production intervals from 160°C to above 300°C). They are often hard (240^{+} MPa compressive strength), abrasive (quartz content above 50%), highly fractured (fracture apertures of centimeters), and under-pressured. They often contain corrosive fluids, and some formation fluids have very high solids content (total dissolved solids in some Imperial Valley brines is above 250,000 ppm). These conditions mean that drilling is usually difficult – rate of penetration and bit life are typically low [5], corrosion is often a problem [6], lost circulation is frequent and severe, and most of these problems are compounded by high temperature.

Lost circulation (loss of drilling fluid into the rock formation) and reservoir damage deserve special mention. Lost circulation is often massive, with complete loss of returns at pumping rates of hundreds of barrels per hour. Geothermal wells have been abandoned because of the inability to get through a loss zone [7], and many more have needed an unplanned string of casing to seal off a problem. Lost-circulation treatment is complicated by the requirement that the treatment of loss zones must not damage the producing formation, but it is often difficult to distinguish between the two.

Finally, geothermal wells produce, relative to oil and gas, a low-value fluid – hot water or steam. For economic viability, then, geothermal flow rates and well diameters must be much larger than comparable oil and gas wells. Oil wells frequently produce through 6 cm tubing, but geothermal wells that supply power plants will generally have production intervals of at least 21.6 cm diameter. Geothermal casing will therefore be larger and more expensive and, also unlike oil and gas, it must be cemented along its complete length, not just anchored at the bottom.

All of these factors will be discussed in more detail below.

Geothermal Rock Formations

With few exceptions, geothermal reservoirs are found in igneous or metamorphic rocks such as granite, granodiorite, quartzite, basalt, and volcanic tuff [8]. Reservoirs in California's Imperial Valley and Mexico's Cerro Prieto fields are among the rare resources in sedimentary formations, and drilling practices in these fields are significantly different from elsewhere. As noted above, these igneous or metamorphic rocks tend to be hard, abrasive, and fractured, which makes drilling difficult, and they are also more variable from

one well to another than is the case in a typical oil and gas reservoir. This means that the learning curve in a geothermal reservoir is not as steep as would be the case with hydrocarbons, but experience is still valuable, and each well will have a share of "lessons learned." This variability is a key factor in assessing the variables that drive well cost, as discussed in the next section.

Depth and temperature of geothermal resources vary considerably. Several power plants (e.g., Steamboat Hills, Nevada and Mammoth Lakes, California) operate on lower temperature fluid (below 200°C) produced from depths of approximately 330 m, but wells in the Geysers produce dry steam (above 240°C) and are typically 2,500–3,000 m deep. In the most extreme cases, an exploratory well with a bottom-hole temperature of 500°C at approximately 3,350 m has been completed in Japan [9], and experimental holes into molten rock (above 980°C) have been drilled both in Hawaii and in Iceland.

Well Cost

Cost of the wells is clearly crucial to the financial viability of a proposed geothermal power project, because the well field – production and injection – can comprise 30–50% of the project's capital cost [10]. Factors that affect well cost are discussed in many places [11], and all of the topics discussed in this entry are related in some measure to the well's cost. It is useful, however, to look specifically at some of the most important cost drivers in geothermal drilling.

Well design: Design of a geothermal well is a "bottom-up" process. Location of the production zone determines the well's overall length, and the required flow rate determines diameter at the bottom of the hole – the well's profile above the production zone is then set by iteration of the successively larger casing strings required by drilling or geological considerations.

Because of the large diameters in geothermal wells, however, casing and cementing costs form a relatively large share of the cost, and the ability to eliminate one string of casing would have a major impact.

The need for directional drilling and the accuracy with which the hole trajectory must be controlled are also important factors in cost, but there is usually less flexibility in those choices as the well is designed.

Trouble: "Trouble" is a generic name for many sorts of unplanned events during drilling, ranging from minor (small amounts of lost circulation) to catastrophic (the BHA is stuck in the hole and the drill string is twisted off). In some cases, experience in the same or similar reservoirs will give a hint that certain types of trouble are likely, but at other times events are completely unexpected. It is difficult, therefore, to estimate a precise budget for trouble, but all well expenditure planning must contain some contingency funds, and this number is often taken to be around 10% of the total budget.

Two kinds of trouble avoidance that have received considerable research effort are lost-circulation treatment and vibration reduction to mitigate bit, BHA, and drill pipe failure. These topics are described in more detail later, but they cannot be dismissed as possible cost drivers.

Rate of penetration (ROP): Many of the costs attributed to drilling are time dependent (primarily related to the rental rate on the rig), so it is clear that anything to speed up the hole advance is beneficial. (Keep in mind, however, that increased ROP at the expense of more trips, or lower tool life, is usually not effective. See the next paragraph.) A tremendous amount of research has been done to improve bit performance, both in terms of drilling speed and life, and there is no doubt that today's bits are far better than those of an earlier generation. Still, even with improved bits it is not always easy to optimize the performance with a new bit design drilling an unfamiliar formation. The three parameters that can be easily changed for any bit/formation combination are rotary speed, weight on bit (WOB), and hydraulics (combination of jet size and flow rate), and it often takes some experimentation to determine the best combination of these factors.

Bit and tool life: Much of the commentary above about ROP applies to bit and tool life. Improved tool life means, of course, that the expense of replacing a bit or other piece of equipment can be avoided or delayed, but there is also a time saving if trips can be eliminated. This becomes more important as the hole gets deeper and the trips take more time.

Comparison: To examine the effect of these factors, the hypothetical well shown in Fig. 3 will have its overall cost calculated with the following changes in the relevant variables. Cost calculations are done with a spreadsheet

program that lists and sums the major variables in drilling cost, and are generally in 2009 dollars, although the key point here is not the absolute value of well cost, but the relative effect of the various changes.

- Well design: The first alternative to the "base case" well is a variation designed with one fewer casing strings (this may or may not be realistic, but serves to demonstrate the effect of well design on cost) (Fig. 4).
- Trouble: The base case well is assumed to have a moderate amount of trouble. There are two lost-circulation events, both in the 44.5 cm interval, and one twist-off in the 31.1 cm interval. Each lost-circulation event is treated by pumping 10 m^3 of cement and waiting 12 h on cement to cure, and the twist-off is assumed to require 80 h for fishing and repair.
- Rate of penetration: Base case bit performance is 10 m/h for 44.5 cm bits, 5 m/h for 31.1 cm bits, and 4 m/h for 21.5 cm bits. "Improved" ROPs are 15, 10, and 6 m/h, respectively.
- Tool life: Base case bit life for the sizes above are 100, 80, and 40 h. Improved values are 200, 120, and 80 h, respectively.

Results: The effects of these improvements are shown in Table 1, where the cost savings from various changes are shown in all possible combinations.

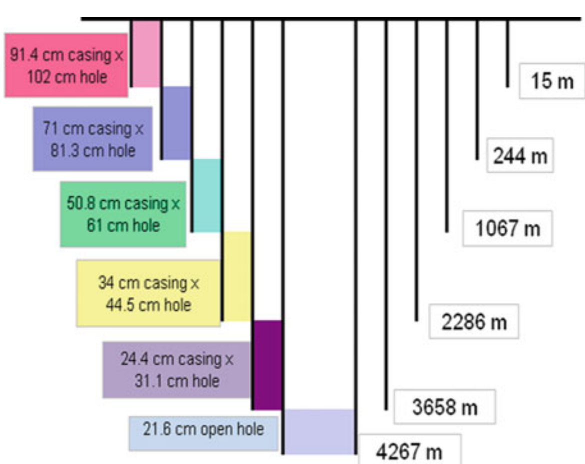
Cost reductions that can be attributed to the various individual improvements are

- Redesign casing to eliminate one string – 18.9%
- Improve rate of penetration – 7.2%
- Improve bit life – 1.9%
- Eliminate trouble – 2.0%

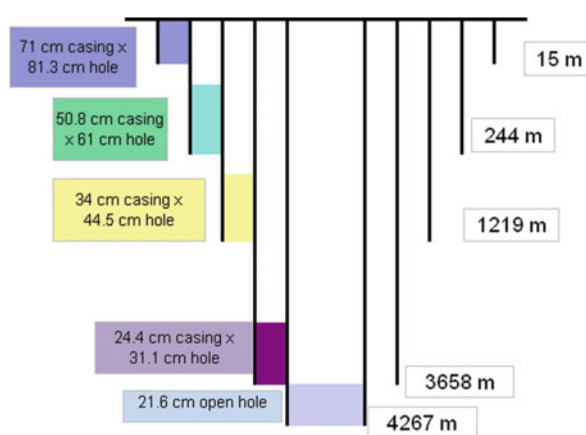
From this analysis it is clear that significant cost reductions may be available. If all the postulated improvements were made, total cost would decrease by almost 29%, or more than $3 million. Most important of the improvements considered was redesigning the casing to eliminate one string, with improved rate of penetration a distant second, although still significant. This statement does not imply that either of these improvements is actually possible in every case, but the numbers do give an indication of priorities when considering research into different drilling technologies. The most important factor to remember in considering well cost is that geothermal wells are *extremely* site specific, much more so than oil and gas wells of similar depth, and so these results are not generic.

The numbers above should be taken with some caution, because of this variability in well cost components with location. To give several examples of exceptions, consider the following:

- The trouble postulated for this well was relatively minor, with two cement plugs and a twist-off that could be retrieved by fishing. In at least one case [12], a geothermal well received 20 cement plugs without curing the lost-circulation problem, and the well was abandoned. As for twist-offs, it is



Geothermal Resources, Drilling for. Figure 3
Base case well design



Geothermal Resources, Drilling for. Figure 4
Alternative casing design

Geothermal Resources, Drilling for. Table 1 Comparison of well costs, assuming different drilling conditions

	Base case	Improve bit life	Improve ROP	Improve ROP and bit life
Base case	$11,560,857.95	$11,345,822.83	$10,733,021.31	$10,691,820.96
Reduce trouble	$11,335,667.78	$11,120,632.66	$10,507,831.14	$10,466,630.80
Eliminate casing string	$9,372,815.35	$9,151,844.66	$8,624,445.23	$8,461,433.57
Eliminate string, reduce trouble	$9,146,089.76	$8,925,119.08	$8,397,719.65	$8,234,707.98

Geothermal Resources, Drilling for. Table 2 Sample well costs from various geothermal projects

Well location	Depth (m)	Production diameter (cm)	Year drilled	Total cost (US$)
Newberry Caldera, USA [14]	2,927	31.1 hole/24.4 liner	1995	2,895,493
Vale OR, USA [15]	1,755	15.9 hole/12.7 slotted liner	1994	920,325
Habanero-2, S. Australia[a]	4,358	15.2 open hole	2007	6,200,000
GPK-4, Soultz, France[a]	5,260	21.6 open hole	2004	5,000,000

[a]The referenced report "The Future of Geothermal Energy," available online at http://www1.eere.energy.gov/geothermal/future_geothermal.html, has an extensive discussion of well cost variation over periods of several decades, and also goes into much greater detail about the factors that drive well cost

often the case that a stuck bottom-hole assembly (BHA) cannot be fished, so that the hole must be side-tracked to go around it – this procedure is much more expensive than simply fishing.

- Differences in site preparation are not included in these spreadsheet calculations, but rugged terrain or an absence of easily available water can have a major impact on well cost.
- Some locations, such as the Imperial Valley in southern California, have extremely corrosive in situ fluids that require titanium casing [13], at a cost exceeding $2 million for the production string.
- Bit-life improvements used in the spreadsheet calculations may be unrealistically high, but this only demonstrates the fact that even very large improvements in that area have relatively small effect in the given well design with the stated drilling performance. On the other hand, rock reduction is often the source of trouble cost, so the reduction in drilling time may not be the only cost saving.

In general, cost information on wells drilled by commercial geothermal operators is tightly held and it is difficult to get extensive data on actual drilling costs. In a few cases, however, such data is in the public domain, and a brief sample is given in Table 2.

Even these few examples show the great variability in cost, a significant fraction of which is caused by economic inflation over time.

Finally, if an operator is considering exploratory wells, there are many advantages to drilling "slim holes" – wells with diameters smaller than would be used for production but large enough to be useful in characterizing the reservoir. This would typically mean final diameters of 7–10 cm, compared to common production diameters of 15–24 cm.

Drilling is cheaper for slim holes than for production wells because the rigs, casing and cementing, crews, locations, and drilling fluid requirements are all smaller; because site preparation and road construction in remote areas is significantly reduced, up to and including the use of helicopter-portable rigs; and because it is not necessary to repair lost-circulation zones before drilling ahead. An extensive slimhole-drilling research program [16] showed that slim holes are consistently cheaper than full-size holes in the same locations, and that the slim holes are adequate to characterize the reservoir.

Planning and Designing the Well

There are two separate but closely related parts of preparing for a drilling project – *planning* the well and *designing* the well. "Planning" means to list, define, schedule, and budget for all the multitude of individual activities required to drill the well, and "designing" means to specify all the physical parameters (depth, diameter, etc.) that define the well itself. Detailed instructions on how to complete this process for even one well would need a sizable volume in itself, and so that is well beyond the scope of this entry, but the following discussion will present a sort of checklist that specifies many of the questions that must be considered during these preparations. (The geographical location of the well can have a major impact on cost, schedule, and even well design, but that choice is a function of exploration for the resource, and so is too variable to be considered as a generic part of well planning.)

Careful planning is critical for any drilling operation. It will not only minimize cost, but will reduce the risk of injury or property damage from unexpected events. A drilling plan should list and define all the activities required to complete the well, with their related costs and times, and should give sufficient descriptions of individual tasks to make clear the sequence in which they must be performed. (A "critical path" approach, showing which operations must be sequential and which can be simultaneous, is often useful. The crux of this technique is that any delay along the chain of sequential operations – the critical path – will cause a delay in project completion, while delay in some other operation may not.) It is also essential that all the contractors and service companies should meet, or at least thoroughly communicate, during the planning stage, so that the plan assigns responsibilities for the various activities and there is no confusion as to what person or company performs each step.

Descriptions in the plan must be relatively detailed. For example, to specify drilling, an interval between two given depths and running casing in it would typically require, at minimum, the following information:

- Bit size and type (include suggested weight on bit and rotary speed, if available)
- Definition of all components of the bottom-hole assembly, and whether downhole motors are to be used
- Expected rate of penetration and bit life (thus, expected time to drill the interval)
- Any directional drilling instructions
- Drilling fluid type and flow rate
- Any required logging during drilling or before casing is run
- Size, weight, and grade of casing
- Proposed cementing program
- Any problems expected in that interval, or special precautions to be taken

A plan can be as simple as a written outline, in list format, of the various activities, or can be quite detailed and in active electronic format. Management software ranges from simple spreadsheets, through freeware available on the Web, to sophisticated planning tools such as Microsoft Project [17]. If one considers commercial planning software specific to drilling, make sure that it can include services that are common in geothermal drilling but not often used in oil and gas, such as mud coolers, high-temperature tools and cement, etc. Clearly, the drilling plan must also be flexible enough to accommodate unexpected events, or trouble, during the project, and there must be a well-defined process to identify the person who is responsible for changes in the plan.

To begin designing the well, a great variety of information is desirable, but it is not always possible to get the complete package. It is worth considerable effort to get as much of it as possible, but sometimes the designer must just go with the best available data. The desirable information includes, but is not limited to, the following parameters.

- Purpose of the well: A given well may serve any one of several different functions – production, injection, exploration, or workover – and the well design will be influenced by its purpose. For example, an exploration well might be of smaller diameter than the one intended for production and, because it might be scheduled for abandonment once the reservoir is characterized, it might also be completed with less attention to the well's longevity (different

cement, casing material, or the like). Some considerations for hole diameter in small exploration wells or "slimholes" are described in the section on "Drilling System Selection Criteria".

- Reservoir conditions: It is extremely useful to know as much as possible about the prospective reservoir; such information might come from previous temperature and pressure logs in offset wells, nearby thermal gradient holes, or geophysical information. Clearly, temperature and pressure are crucial, but brine chemistry is also very important because it can have a major impact on casing selection and cost.
- Logistical requirements: It is common that, for reasons including a power sales contract, other financing requirements, or even weather, a drilling project must be completed on a given schedule. If this is the case, it can complicate planning because of factors ranging from drill rig availability to acquisition of the necessary permits. It is also more or less a standard condition that any lease site will have regulatory stipulations that affect drilling fluid disposal, cuttings disposal, possibly water supply, and even air-quality requirements that will necessitate emissions control on the rig engines. The well planner has little recourse in dealing with these factors, but it is certainly essential to consider them in the planning process.
- Likely problems in drilling: Experience in similar wells or general knowledge of the reservoir can sometimes offer a prediction of what problems may be encountered in drilling the well. If this knowledge is available, it will guide the preparations in many ways: having lost-circulation material (LCM) for under-pressured formations; appropriate drilling fluid additives for corrosive brines or for exceptionally high temperatures; high-temperature logging or steering tools and drilling motors if those tools will be used in a hot hole; and stand-by fishing tools and possibly shock absorbers in the BHA if there is likely to be rough drilling with twist-offs. It may also provide better definition of the best operating envelope (weight on bit, rotary speed, and hydraulics) for the bit in specific formations.
- Casing requirements: The heart of well design is the specification of the casing program, which will be discussed in more detail below. Parameters that determine the casing requirements include the following: nominal production rate from the well and the casing diameter implied by that flow rate, depth of the production zone, expected temperature, brine chemistry, whether the completion will be open hole or slotted liner, well trajectory (vertical, directional, or multi-leg), kick-off point (if directional), need for special casing connections, and the length of individual casing intervals.

In general, the well is designed from the bottom up, that is, the expected depth of the production zone and the expected flow rate will determine the wellbore geometry and casing program and most of the equipment requirements will follow from those criteria. Because geothermal wells produce a relatively low-value fluid – hot water or steam – flow rates must be much higher (often >100,000 kg/h) than for oil and gas wells, and geothermal wells produce directly from the reservoir into the casing, instead of through the production tubing inside casing as in most oil wells. If there is two-phase flow in the wellbore, larger casing diameter where flow is vapor dominated will significantly reduce pressure drop, improving productivity [18]. Finally, many lower-temperature geothermal wells are not self-energized and must be pumped, either with line-shaft pumps driven from the surface or with downhole submersible pumps (and so the well's design must allow for pump removal). All these factors combine to drive geothermal casing diameters much larger than oil and gas wells of comparable depth – typical casing sizes in geothermal production zones are 20–34 cm.

There are three important considerations in designing the casing:

- Because each casing string limits the diameter of the drill bit and successive casing strings that can pass through it, the hole diameter decreases as the well gets deeper.
- Because of casing costs and diameter reduction, it is beneficial to make the intervals between casing points as long as possible.
- The incidence of problems or trouble increases as the wellbore intervals between casing points grow longer.

The two latter points counter each other – it is highly desirable to drill long intervals between running successive casings, but doing so greatly increases the probability of trouble. If a "contingency string" is needed to isolate a troublesome wellbore zone, this imposes a significant cost for the additional casing and cementing. It also implies the necessity of starting with larger diameter casing above the contingency string, to preserve the required bottom-hole diameter, or of completing the well with smaller bottom-hole diameter than was desired, if no provision for the contingency string was included in the plan.

Given a bottom-hole depth and diameter, determination of the casing intervals above that depends on several factors, including rock properties, formation fluids, or even regulatory requirements (some agencies require that at least 10% of the wellbore always be behind surface casing down to the next casing point, and 1/3 the well behind casing below that). There are many common reasons to set casing in a particular interval:

- Protect an aquifer – regulations require sealing off aquifers to prevent their contamination by wellbore or drilling fluids.
- Isolate troublesome formations – these can be unstable (sloughing, swelling, or unconsolidated) formations, zones with high or incurable lost circulation, or a depleted-pressure zone above the production horizon.
- Fluid pressure control – although more common in oil and gas than in geothermal, drilling fluids often contain additives that bring the specific gravity of the fluid well above that of water, so that the weight of the fluid column will control the downhole pore pressure in the formation. This often leads to the situation in which the higher pressure of the drilling fluid exceeds the fracture gradient of the formation, leading to lost circulation or even loss of well control.
- Define the production zone – geothermal reservoirs can have more than one productive zone and casing is sometimes set to preferentially allow production from the selected zone.

There are many other reasons that casing might be set at a particular depth, but this list gives a flavor of how variable those reasons can be. Once the general casing profile is selected, the casing for each individual interval, or string, is characterized by three basic measurements: diameter, weight, and grade. Diameter is straightforward; it is just the nominal outside diameter for that interval (although this does not include the couplings, which are larger than the casing body and control the smallest possible inside diameter of the next larger string). Weight, expressed in weight units per unit length, is actually a measure of the wall thickness of the casing; heavier casing has smaller inside diameter, since the outside diameter must remain constant for a nominal size. The casing's grade is primarily related to the material's tensile strength, although there are some metallurgical variations aimed to withstand specific effects, such as corrosion, of the wellbore fluid chemistries.

Casing has to withstand different kinds of loading in different situations, and the most common design criteria are for burst pressure, collapse pressure, axial tension, and buckling. Burst pressure and axial tensile strength are a function of the casing grade, but collapse and buckling are more related to the wall thickness, because they are determined by the material's elastic properties as well as its tensile strength.

Although reasonably simple casing designs can be done with hand calculations and manufacturers' handbooks, the general topic can be very complex, and detailed procedures for casing design are well beyond the scope of this entry. Extensive resources are available. All drilling engineering textbooks [19] have sections on casing design, and an Internet search for "casing design software" will indicate the multitude of options to be found among drilling service companies. Although all of these methods are likely to produce satisfactory casing designs, engineering judgment is still important and it is of significant benefit to have a veteran drilling engineer with geothermal experience to at least review a proposed casing program.

Drilling System Selection Criteria

Most of the criteria used to select a drill rig will be derived from well parameters; specifically diameter, depth, and casing design. The process of planning and

designing the well will have established the diameter, which is the primary criterion for whether the well is considered a “slimhole” or will be a conventional well and, thus, what kind of rig will be used.

Several factors define the minimum hole diameter, and also bear upon whether a core rig can be used for the hole.

- Logging tools – Typical temperature-pressure-spinner logging tools will fit into almost any reasonable hole size, but if more complex tools, especially imaging tools such as a formation micro-scanner or a borehole televiewer are to be used, the heat-shielding they require at high temperature sometimes defines a minimum hole size.
- Core size – If core is required to validate a geologic model of the reservoir or to assess the fracture dip, density, and aperture, then a coring rig is advantageous, compared with taking core samples with a rotary rig, but the core size must be considered. Diameter is not too important for fracture data, but sometimes a rock mechanics evaluation will need a minimum core diameter. Larger diameter core also gives better recovery in highly fractured or unconsolidated formation.
- Packers – Inflatable packers are sometimes used to isolate a specific section of the wellbore for injection tests, fluid sampling, or other diagnostics. In general, this means that some kind of logging or sampling tool must be run through the packer into the zone below it, and the size of this tool will determine the minimum size of the packer and thus the hole. Based just on the diameter of the cable head for most logging cables, it would be very difficult to run a pass-through packer in a hole smaller than approximately 100 mm diameter.
- Flow test – If a flow test is expected after drilling, there are two advantages to keeping the hole diameter as large as possible: scaling up for predicted flow in a large-diameter well will be more accurate; and if the combination of depth, pressure, and temperature means that the well’s ability to produce is marginal, a larger diameter hole is more likely to flow. The larger-diameter wellbore is particularly important if the flow turns two phase.

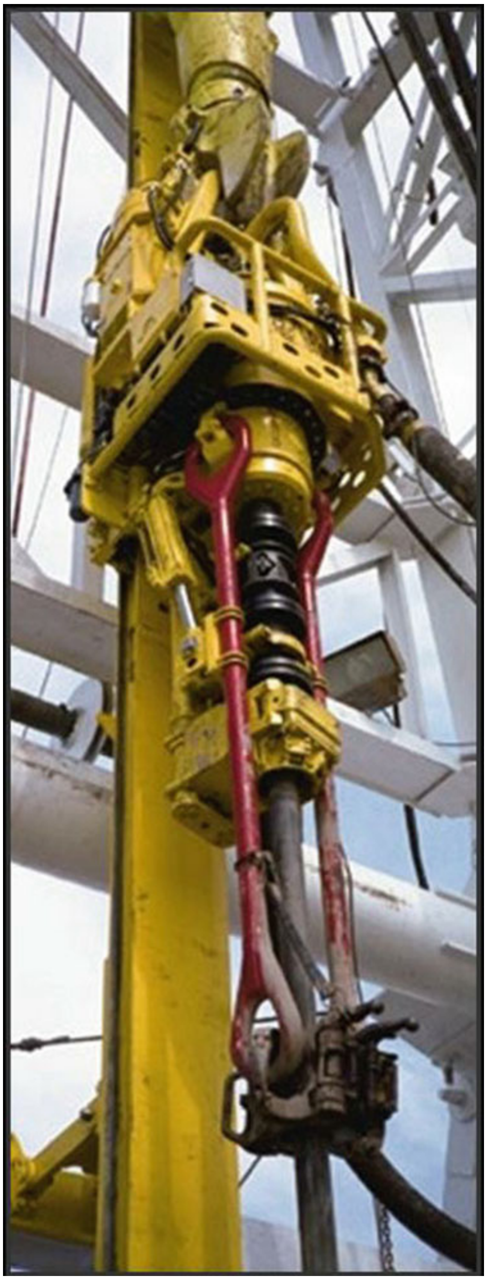
If all these factors indicate that a slimhole will satisfy the requirements, then a minerals-type coring rig can often yield significant cost savings for two reasons:

- Smaller casing, tools (bits, reamers, etc.), and cementing volumes
- The ability to drill with complete lost circulation (no returns to the surface)

Coring rigs (see Fig. 5) are fundamentally different from rotary rigs in the way that they retrieve core. A typical coring rig used for minerals exploration stores the core as it is cut in a tube in the lower end of the drill string. At the end of the coring run, a wireline is

Geothermal Resources, Drilling for. Figure 5
Typical coring rig, mast is ~15 m high

Geothermal Resources, Drilling for. Figure 6
Rotary drill rig, mast is ~55 m high



Geothermal Resources, Drilling for. Figure 7
Top drive, photo courtesy of National Oilwell Varco

lowered down the inside of the drill string and is latched into the top of the core tube to retrieve it to the surface. This not only gives a continuous core over the interval of the hole, but is much faster than tripping the drill string to retrieve the core sample as is done in rotary rigs.

If a large-diameter hole is required, then a conventional rotary rig (see Fig. 6) will probably be used and the basic choice to be made is whether it should be a top drive. For many years, as described in the Overview, the drill string was turned by a “rotary table” in the rig floor. A square or hexagonal bushing in this table applies torque to the “kelly” (the topmost part of the drill string), which is square or hexagonal in cross section, so that it can be turned by the table and still slide downward as the hole advances.

In the early 1980s, however, a new system in which the drill string was turned by a motor hanging directly beneath the traveling block gained commercial acceptance (see Fig. 7). This “top drive” technique has at least two critical advantages: instead of adding drill pipe one joint at a time as the hole advances, the driller

can work with stands (two or three joints) of pipe, eliminating time and connections, and the driller can rotate and circulate while tripping. Detailed comparison of operations for one offshore platform [20] showed an 11% decrease in drilling time, and the ability to circulate while tripping is especially important for geothermal wells, because it allows protection of temperature-sensitive tools while tripping into the hole. In one geothermal reservoir [21], it was reported that bit life was improved three- to sixfold by circulating during trips into the hole. The circulation/rotation capability is also useful for avoiding stuck pipe and for working through tight spots during tripping. Top-drive rigs generally cost more in daily rental, but it is often cost effective to use one.

Many considerations will affect the final rig choice but, aside from the purely economic factor of the price quoted by the drilling contractor, the following aspects of the rig should be the minimum list of qualities upon which to make a decision.

Rig capacity: This usually refers to hook load – the weight that can be suspended from the rig's hoisting system. Clearly, the drill string weight, with all the bottom-hole assembly, is an important part of this requirement, but it should be remembered that the casing is often the heaviest load handled during a drilling project.

Rig footprint: The drilling contractor should provide a dimensioned diagram or map of the rig setup in operating mode. It should clearly show: access points and traffic patterns to various parts of the rig; where different operations (mixing mud, mud logging, etc.) are performed; and the locations where various consumables are stored. If the planned drilling operation includes mud pits, or a water well, those should also be on the map. The contractor's quote will give a cost figure for mobilizing and demobilizing the rig (moving the rig to and from the drilling location) but there should also be an indication of how many truck loads this will entail, and what road clearances are required, in case there are regulatory issues at sensitive locations.

Pump capacity: As discussed under section Drilling Fluids, the pumps must have enough volumetric capacity to give sufficient velocity in the annulus to lift the cuttings. The pumps must also have enough pressure capacity to give the desired pressure drop through the bit jets, and possibly drive a downhole drilling motor, if that is planned or a likely contingency.

Fluid cleaning: These requirements should be defined in consultation with the mud engineer/company, and the rig's shakers, desanders, desilters, and centrifuges should be adequate to the job. There should be some operational consideration of the rig's compatibility with any environmental regulations that affect disposal of the drilling fluid and cuttings, such as the requirement for a closed-loop fluid system with no discharge to the environment.

Drill string and BHA: The bottom-hole assembly design should be defined during planning, so it is clearly important that the rigs have the correct tools, tongs, and fixtures (bit breakers, elevators, etc.) to handle all components of the drill string. It should also be made clear in the contractor's quote whether drill pipe is included in the rig's daily rate. If so, the planner should make certain that it is the correct weight and grade and, if not, the planner should assure that another source of pipe is available.

High-temperature capability: When drilling geothermal wells, it is clearly necessary that any of the rig's downhole or surface equipment that will be exposed to high temperature has that capability. This may be especially noticeable in drilling fluid returns, which will probably be much hotter than in conventional drilling. In most locations, regulatory guidelines will require use of mud coolers when returns exceed a specific temperature, but even with coolers, operating personnel should be aware that hot fluid will create higher-than-normal thermal expansion forces, and that any elastomer seals may become vulnerable to the high temperature.

Rig instrumentation: Complete information about the rig's performance is essential for safe, efficient operation, and the project planner should include an instrumentation list in the rig criteria. Detailed requirements will vary from project to project, but a typical set of desirable measurements includes the following: drilling fluid inflow and outflow rates, drilling fluid inflow and outflow temperatures, standpipe pressure, rotary speed, weight on bit, torque, and kelly height, if available. All these measurements should be digitally recorded on a data logger at reasonably short intervals ($\sim$ every 5 s) so that they can be easily stored and retrieved, but selecting the interval between measurements is not straightforward. For "steady-state" drilling, in which

operations are routine, data points every 5–10 s are adequate, but for transient events such as the beginning of a new bit run or the onset of unstable, possibly damaging, drilling conditions, high-resolution data can be extremely valuable. Collecting high-speed data implies very large data files on long drilling projects, which may be a storage problem, but low-speed collection that gives more manageable amounts of data may not give the resolution needed for short-duration events.

Rig instrumentation is often coordinated between the drilling contractor and mud-logging company; see the Instrumentation section below.

Support: In general, rig malfunction or breakdown is one of the less likely kinds of drilling trouble. If the drill site is in an especially remote location, however, it is worth considering how far away the rig's support services may be.

Crew and training: It is not always possible to know in advance who will be working on the rig, but the importance of a well-trained, experienced crew to the project's success cannot be overstated. In the course of evaluating proposals from drilling contractors, every effort should be made to find out the experience and qualifications of the rig crew and supervision.

Like many aspects of drilling, selecting a rig often turns out to be more complicated than it first appears. Keys to a successful choice revolve around having a clear and detailed concept of what is needed for the project. It is frequently very valuable to have an experienced geothermal drilling engineer assigned to the specific task of rig selection, because any extra cost incurred here will almost certainly prove to be well spent.

Geothermal Resources, Drilling for. Figure 8
Milled tooth roller-cone bit (Photo courtesy of Reed-Hycalog NOV)

Drill Bits and Bottom-Hole Assembly

As described in the Overview, the bit is at the lower end of the drill string where, as it rotates, it crushes, gouges, grinds, and cuts the rock to advance the hole. The bottom-hole assembly (BHA) comprises all the components, including the bit, up to the lower end of the drill pipe.

Bits

The bit is usually either a roller cone, which crushes and gouges the rock as the cones turn and their teeth successively come in contact with unbroken areas, or a drag bit, which shears the rock in the same way that a machine tool cuts metal. Because of this shearing action, drag bits are inherently more efficient than roller-cone bits.

The great majority of roller-cone bits today have three cones, with either milled steel teeth (see Fig. 8) that are part of the cone itself or hard-metal (usually tungsten carbide) teeth (see Fig. 9) inserted into the body of the steel cone. Milled-tooth bits are less expensive but are suited only for softer formations. Insert bits are used in medium to harder formations, with the size, shape, and number of inserts varied to fit the specific drilling conditions. The bits are available with either roller or journal bearings, depending on operating conditions, and the bearings, seals, and lubricants should all be specified to withstand high temperatures if the bits are to be used in geothermal drilling. Roller-cone bit technology is very mature – over 100 years since the first patent [22]. Although bit companies still do constant research, and have made significant progress over the last 20 years,

Geothermal Resources, Drilling for. Figure 9
Insert roller-cone bit (Photo courtesy of Reed-Hycalog NOV)

Geothermal Resources, Drilling for. Figure 10
PDC drag bit (Photo courtesy of Reed-Hycalog NOV)

the improvements have been incremental. Since the 1950s, R&D for roller-cone bits has alternated between better bearings and more durable cutting structures, depending on which is the dominant failure mode at the time. Roller-cone bits dominate drilling for geothermal resources because of their durability in the hard, fractured rocks that are characteristic of those reservoirs.

Because drag bits reduce rock with a shearing action, they are inherently more efficient than roller-cone bits. Drag bits with polycrystalline-diamond-compact (PDC) cutters (see Fig. 10) began to be widely used in the early 1980s for their ability to drill faster and last longer in soft to medium formations, and they now dominate oil and gas drilling. A particular advantage of drag bits for geothermal drilling is that they do not have any moving parts, so temperature limitations on bearings, seals, and lubricants are not a factor. Unfortunately, PDC bits usually do not have acceptable life in hard or fractured formations, and are not generally used in geothermal drilling. A great deal of work has been done to extend their use to harder rocks [23, 24, 25], and significant progress has been made, but acceptance by the geothermal industry has been minimal. Wider use of these more efficient bits would be a significant technology advance.

If the drilling plan calls for a slimhole to be drilled with a minerals-type core rig, bits are completely different. Much of the rock volume removed from the hole is in the form of core, and the rock cuttings themselves are much smaller, because virtually all hard-rock coring is done with diamond-impregnated bits (see Fig. 11) that grind away the rock.

Principal variations in this kind of bit are the diamond grain size, the diamond grain density, and the hardness of the matrix metal in which the diamond grains are embedded. These bits typically turn at much higher speeds than conventional rotary bits (either roller cone or drag) and have a much lower drilling fluid flow rate because of the smaller annulus between the drill rods and the borehole wall.

Drill Pipe

Choosing the drill pipe specifications can be complicated in some cases, but the primary considerations are the following.

Geothermal Resources, Drilling for. Figure 11
Diamond-impregnated core bit

- Strength: The principal requirements are for tensile and torsional strength, so that the pipe can pull the drill string out of the hole (often with some overpull required because of tight spots, or even partially stuck pipe) and can apply the torque needed to rotate the bit. Internal pressure may become an issue in some cases, and bending strength is important in directional drilling.
- Size: Given that several different pipe configurations might be strong enough, a major driver for size selection is hydraulics. The internal diameter of the pipe must be large enough to avoid excessive pressure drop in the circulating drilling fluid. It is also necessary that the inside diameter of the pipe be large enough to pass any expected logging tools, and there are sometimes considerations of whether the pipe size is adaptable to fishing tools in the event of trouble. On the other hand, the outside diameter of the drill pipe tool joints must clearly be small enough to pass through the smallest casing to be used, with enough clearance for the same fluid flow on the outside of the pipe.
- Corrosion resistance: Many formation fluids are corrosive; this is especially true in much geothermal drilling. Several special grades of drill pipe are made from alloys designed for corrosive environments.
- Wear resistance: Because many geothermal formations are extremely abrasive, drill pipe tends to wear much faster than in other types of drilling. "Hard banding" (applying layers of wear-resistant material such as tungsten carbide to the outside diameters of the tool joints) is common in geothermal drilling.

Bottom-Hole Assembly (BHA)

A drill string is relatively flexible compared to its length (a scale model, dimensionally, of a 3,000 m drill string is a piece of steel wire, the thickness of a human hair, one meter long). The total weight of the drill string is generally much greater than the desirable force on the bit, so the rig's hoisting capability holds back some of the string weight to control force on the bit. The upper part of the drill string is therefore in tension, while the lower part that applies force to the bit is in compression. Drilling with the relatively thin drill pipe in compression may cause buckling, so it is important that the neutral point (where the drill string stress changes from tensile to compressive) falls within the *drill collars*, which are thick-walled cylinders at the bottom of the drill string. The outside diameter of the collars is controlled by the necessary annulus between the collars and the wellbore, the inside diameter by hydraulic consideration (large enough to prevent excessive pressure drop), and the overall length by that required to provide maximum expected weight on bit. Other components that are often part of the BHA include the following.

- Stabilizers: Because the drill collars and other components must be smaller than the wellbore diameter to provide a path for fluid circulation, they can have major lateral deflections. This can produce serious vibration as well as high fatigue loads in the threaded connections, so stabilizers that have full wellbore diameter on ribs along the outside surface but leave a flow path between the ribs are widely used at multiple points in the bottom-hole assembly.
- Reamers: The outside diameter, or "gauge" of drill bits tends to wear, causing the hole to be smaller

than the nominal diameter. When a new bit is tripped in, it has to ream the smaller hole out to the desired diameter, which is time consuming and which causes the new bit to wear prematurely on its own outside diameter. Additional cutting elements, either as fixed cutters or as toothed, cylindrical rollers are often added to the BHA just above the bit, to help maintain the full hole diameter.

- Shock absorbers: When drilling in hard or fractured formations, or those in which soft and hard stringers are interbedded, high vibration loads are common. Shock absorbers, or dampers, are used to attenuate the vibrations transferred to the upper part of the BHA and drill string.
- Jars: If the drill string is stuck in the hole, it can sometimes be released by the impact force produced by jars. These function by suddenly releasing energy stored in the drill string by pulling up on it and stretching it. The two principal types are mechanical jars and hydraulic jars, but both operate on the same principle. Jars are generally used when fishing, but some drillers prefer to have jars already in the drill string during normal drilling.

Directional Drilling

During normal drilling, the pendulum effect of the heavy drill collars tends to keep the hole vertical, but for many of the following reasons it is often necessary to guide or steer the hole's trajectory in a specific direction – institutional, legal, or topographic issues prevent the drill rig from being directly over the geologic target; it is economical to drill several wells from one prepared site; and, particularly for geothermal wells, it is important for the wellbore to intersect as many formation fractures as possible.

Directional drilling is a relatively complex technology and there are a number of ways to drill a deviated hole, but the most common is to use a downhole motor (hydraulically powered by drilling fluid flowing through it) that turns the drill bit without rotating the drill string. A "bent sub" points the motor and bit at a slight angle to the axis of the drill string or a "bent housing" introduces an angle between the motor and the bit, and since there is no rotation, the bit continues to drill in the direction it is pointed. The difficulties inherent in directional drilling are aggravated in geothermal wells because both the electronic tools used to control and survey the well trajectory and elastomer elements in the motors are susceptible to high temperature. Progress has been made in both of these areas, but it is still often a technical challenge.

Drilling Fluids

Overview

Drilling fluid flows down the drill pipe, through nozzles in the bit, and back up the annulus between the pipe and wellbore wall, carrying the cuttings produced by the bit's action on the formation. (An alternative method, called reverse circulation [26], is sometimes used – the fluid flows in the opposite direction, down the annulus and up the inside of the drill pipe, but it is not common – see the Section Lost Circulation.) Drilling fluids can be either liquid or gas, and liquid-based fluid is universally called "mud" because the first fluids were just a mixture of water and clay.

Drilling mud is made up of three principal components:

- Base liquid: Oil, freshwater, or saltwater can be used as a base liquid in drilling muds, but oil and saltwater are almost totally restricted to hydrocarbon drilling. Freshwater muds are used for geothermal drilling.
- Active solids: Active solids are the clays and polymers added to the water to produce a colloidal suspension. They determine the viscosity of the mud and are known as viscosifiers.
- Inert solids: Inert solids are those added to the mud either by drilling (i.e., particles of the formation) or by using barite as a weighting material. These solids increase the density of the mud without appreciably affecting the viscosity.

Historically, most geothermal drilling fluids have been a fairly simple mixture of freshwater and bentonite clay, possibly with polymer additives [27]. Air drilling is relatively common, especially in areas like the Geysers in northern California, where the reservoir produces dry steam, and air drilling also has advantages in drilling performance because the rate of penetration is usually higher with lighter fluid. Aerated mud has

a gas, usually air but sometimes nitrogen if corrosion is serious, injected into it to lighten it, and is also common where lost circulation is a significant problem.

Drilling Fluid Functions

As noted above, the principal function of drilling fluid is to clean the hole of cuttings, but there are several other purposes:

- Cool and clean the bit: keeping the bit cool, especially if it has elastomer seals, is critical to its life.
- Lubricate the drill string: this can be a significant factor in deviated (non-vertical) wells, where the drilling string is lying against the wellbore wall.
- Maintain the stability of the borehole: the proper drilling fluid can help control swelling or sloughing formations, thus lessening the risk of stuck drill pipe. It is also important that the fluid hold the cuttings in suspension when circulation is stopped, so that they do not fall back and pack around the bit and BHA.
- Allow collection of geological information: the cuttings brought back to the surface by the fluid help to identify the formation being drilled.
- Form a semipermeable filter cake to seal the pore spaces in the formations penetrated; this prevents fluid loss from the wellbore.
- Control formation pressures: if high downhole pressures are present or expected, dense material can be added to the drilling fluid to increase its specific gravity, thus resisting the downhole pressure.
- Transmit hydraulic horsepower: this power can be used for driving a drilling motor or for cleaning the hole and/or the bit.

Drilling Fluid System

It should be emphasized that the drilling fluid is part of a *circulating system*, comprising the fluid itself, the mud pumps, and mud-cleaning equipment. The pumps must have sufficient capacity (flow rate and pressure) to provide adequate bottom-hole cleaning, high annular velocity to lift the cuttings, and enough hydraulic horsepower to drive downhole motors and provide the designed pressure drop through the bit jets.

When the cuttings-laden mud returns to the surface, it passes through a series of devices to remove the cuttings. The first of these is usually the shale shakers, which have tilted, vibrating screens that filter out larger cuttings and let them slide off into collection containers; next are usually hydrocyclones, which use fluid inertia to swirl the fluid in a conical chamber, letting the solids drop out the bottom; and finally, centrifuges spin the fluid to extract the finest particles through their density difference. Effective mud cleaning is important for drilling performance as well as cost control. If the fluid has to be discarded because of inadequate cleaning, it is expensive both in material cost and in time loss.

Drilling Fluid Properties

The drilling fluid will be designed to have certain properties, and it is critical to monitor and control these properties at all times. Design and maintenance of drilling fluids is a complex topic, covered in great detail in many sources [28, 29] but primary attributes of fluid for a given well include the following.

- Viscosity: it is vital that the fluid's viscosity be high enough to lift cuttings out of the well as the fluid circulates, and to hold the cuttings more or less in suspension when circulation is stopped.
- Density (or specific gravity): if formation pressures are expected to be high, then the fluid can be weighted to help control them but, as is often the case in geothermal wells, if formation pressures are low, then the fluid should be as light as possible to avoid lost circulation.
- pH: the alkalinity of the fluid is important for corrosion control and for its reaction with certain formation constituents; normal pH is 9.5–10.5, but higher values are not uncommon.
- Filter cake: this is a measure of how well the fluid forms an impermeable layer on the borehole wall to prevent leakage into the formation's natural permeability. (This is typically more important in oil and gas drilling than in geothermal.)
- Solids content: this is a measure of how well the mud is being cleaned, and can also determine when the mud should be discarded or diluted.

There are standard procedures [30] for testing these and other parameters of the drilling fluid, and this testing is normally done at least daily in the field by the drilling fluid specialist or "mud engineer."

Successful mud systems need at least these three attributes:

- Stability: The desired properties of the fluid, once established, should be stable under normal drilling conditions.
- Easy treatment: If the desired fluid properties are lost, treatment should be available to restore them.
- Property testing: Tests and testing equipment should be available to identify fluid properties and indicate any treatment required.

Although the underlying principles of drilling fluids described in the extensive literature are the same for oil/gas and geothermal drilling, high temperatures affect many of the clays and additives used to tailor the fluid properties. Some considerations unique to geothermal drilling are listed below, based heavily on the cited reference [31]:

- Viscosity control: high-quality bentonite clay is the principal vicosifier used in geothermal drilling. Several polymers, available both in liquid and powder form, are also useful but they tend to degrade at high temperatures over long periods of time, so their principal use is for high-viscosity sweeps to clean the hole before cementing, trips, or other activities that require stopping circulation. It is also sometimes necessary to decrease the viscosity, if drilled solids or high-temperature gelation have raised it too high. Proprietary blends of low-molecular-weight polymers and starch derivatives have recently been developed and are effective both in thinning the mud and in inhibiting gelation.
- Solids removal: at high temperatures, the drilled solids tend to take up the available water more vigorously than at lower temperatures, so effective mud cleaning is even more important than usual to prevent gelation and viscosity increase.
- Filtrate (water loss) control: in the past, geothermal filtrate requirements were often more rigorous than necessary. It is important to analyze the filtrate requirements, not only for each well, but for each interval, so that expensive additives are not used without good cause. Lignite has long been the most common geothermal water-loss reducer, but proprietary polymers are also becoming common.
- Alkalinity: high pH is necessary to control the effect of some wellbore contaminants (CO_2 and H_2S), to reduce corrosion, and to increase the solubility of some mud components (lignite, etc.). Addition of caustic soda (NaOH) has been the traditional method of increasing alkalinity, but caustic potash (KOH) is becoming more common in geothermal drilling because of its benefits to wellbore stability.
- Lubricity: the drill string sometimes needs extra lubrication when directional drilling, and lubrication is very often needed when core drilling, especially when drilling without returns. Hydrocarbon-based lubricants often lose their effectiveness at high temperature, but there are proprietary, environmentally friendly lubricants that offer good performance at sustained high temperature.

Finally, there are instances in which it is desirable to drill with clear water, or clay-free drilling fluids, especially in production zones where conventional clay-based muds create a risk of formation damage. This technique requires a copious water supply, and cannot be used in all wells, but has proven successful in Iceland and in Mexico [32].

Planning the Mud Program

Some general guidelines [33] for planning the drilling fluids program are given below, with a reminder that every well is different and there are very few, if any, generic procedures that can be used without modification. A pre-spud meeting of all operating, drilling, environmental, and service company personnel is highly recommended. Discussions of the drilling plan and contingencies may eliminate trouble later in the program. Once there is agreement on the drilling plan, then the mud program should be planned with the following considerations.

1. Water: Since water is basic to the mud system, it is important to know the quality, quantity, and cost involved with the makeup water. Poor quality makeup water may require chemical treatment prior to its use.
2. Type and thickness of the geologic strata: This is not always known before drilling, but fluid properties must be planned with the best available information about downhole conditions, that is, the reactions between drilling mud and formation.

3. Site accessibility: Make sure that supply trucks have reasonable access to the site and that rig placement in relation to pits, bulk storage, etc., is convenient to reduce handling.
4. Climate: Extremes of heat, cold, and precipitation can affect the mud system and products.
5. Drilling equipment: Make sure that the surface equipment, such as pumps, mixing and circulating tanks, mixing equipment, and solids control capabilities are adequate for the hole size, downhole tools, etc.
6. Environmental considerations: If at all possible, use nontoxic, easily disposed drilling fluids. All personnel should know all regulations pertaining to the job.
7. Manpower: The experience, skill, supervision, and attitude of the rig crews are of paramount importance to a successful drilling program.

This chapter is intended to give some flavor of the complexity of the process that is designing and maintaining a drilling fluid system. It is worth a great deal of attention in preparation for a project, because a high percentage of the problems encountered in drilling are related in some way to the fluids.

Lost Circulation

The most expensive problem routinely encountered in geothermal drilling is lost circulation, which is the loss of drilling fluid to pores or fractures in the rock formations being drilled. In addition to the cost of the drilling fluid itself, the fluid loss and inadequate hole cleaning can create many other drilling problems including stuck drill pipe, damaged bits, slow penetration rates, and collapsed boreholes. Lost circulation represents an average of 10% of total well costs in mature geothermal areas [34] and often accounts for more than 20% of the costs in exploratory wells and developing fields. Well costs, in turn, represent 35–50% of the total capital costs of a typical geothermal project; therefore, roughly 3.5–10% of the total costs of a geothermal project can be attributable to lost circulation.

Combating lost circulation can be approached in different ways – drill ahead with lost circulation; drill with a lightweight drilling fluid that will have a static head less than the pore pressure in the formation; mix the drilling fluid with fibrous material or particles that will plug the loss apertures in the formation; or pause in the drilling and try to seal the loss zones with some material that can be drilled out as the hole advances.

Drill with Lost Circulation

Under some conditions, it is practical to drill without returns, particularly in the case of core drilling, where the cuttings are very fine and where most of the rock comes out of the hole in the form of core. In many slimhole exploration holes, intervals of hundreds of meters have been drilled with complete lost circulation [16], but this can only be done if the formations are competent enough to remain stable.

Another technology that is useful with lost circulation is dual-tube reverse circulation [35] (DTRC). This method uses a drill string of two concentric tubes, with the drilling fluid passing down the annulus between the inner and outer tubes, circulating out through the bit, and carrying the cuttings back up through the center tube. This means that it is only necessary to maintain fluid around the bit and bottom-hole assembly, so drilling with complete lost circulation is possible. This technique has been used on several geothermal wells [36] and in one case [37] reduced the cost per foot of drilling comparable wells by more than one-third.

Lightweight Fluids

Aerated fluids – liquid with gases injected into it – produce a static head less than the pore pressure and are a common remedy for lost circulation in geothermal drilling. Aqueous (water-based) foam is attractive because of its simplicity, but it is important to use the proper surfactant that has stable properties at high temperature. Considerable modeling was done in the early development of aqueous foam for geothermal drilling [38, 39]. In addition to numerical models of the foam structure and rheology, a laboratory flow loop measured pressure, temperature, and flow rate at different points to allow experimental confirmation of a rheological model.

Aerated drilling is now used extensively in many locations, and recent experience has shown that its use not only avoids problems with lost circulation but may improve the well's productivity after drilling [40].

Lost-Circulation Materials (LCM)

Lost-circulation problems can generally be divided into two regimes, differentiated by whether the fracture aperture is smaller or larger than the bit's nozzle diameter. Clearly, LCM particles that will plug the bit are unacceptable, but for smaller fractures or for matrix permeability, the wellbore can theoretically be sealed by pumping solid or fibrous plugging material mixed with the drilling fluid – this method is much less effective with larger fractures. Very many substances have been used in the oil and gas industry to plug lost-circulation (LC) zones, but most of them have been organic or cellulosic materials that cannot withstand geothermal temperatures. LC zones in oil and gas also tend to be dominated by matrix permeability rather than the much larger fracture apertures common in geothermal reservoirs. Although traditional organic LCM can be used in the upper, cooler, intervals of a well, and several candidate materials that will withstand high temperature have been identified [41], LCM, in general, has often been unsuccessful in geothermal drilling.

Wellbore Sealing

Fractures too large to be plugged by LCM can only be sealed by withdrawing the drill string from the hole and injecting some liquid or viscous material that will enter the fractures, solidify to seal them, and then have its residue removed by resumption of drilling. Conventional lost-circulation treatment practice in geothermal drilling is to position the lower end of an open-end drill pipe (OEDP) near the suspected loss zone and pump a given quantity of cement (typically 10 m^3) downhole. The objective is to emplace enough cement into the loss zone to seal it; however, this does not always occur. Because of its higher density relative to the wellbore fluid, the cement often channels through the wellbore fluid and settles to the bottom of the wellbore (the larger diameters of geothermal wells aggravate this problem, compared to oil and gas). If the loss zone is not on bottom, the entire wellbore below the loss zone must sometimes be filled with cement before a significant volume of cement flows into the loss zone. Consequently, a large volume of hardened cement must often be drilled to reopen the hole, which wastes time and contaminates the drilling mud with cement fines. Furthermore, because of the relatively small aperture of many loss-zone fractures, the loss zone *may* preferentially accept wellbore fluids, instead of the more viscous cement, into the fractures. This causes dilution of the cement in the loss zone and loss of integrity of the subsequent cement plug. As a result, multiple cement treatments are often required to plug a single loss zone, with each plug incurring significant time and material costs. At least three different approaches have tried to improve this process.

- Cementitious mud: As implied by the name, this is drilling fluid with cement and other materials added to satisfy the criteria: (1) compressive strength above 3.4 MPa after 2 h cure, (2) permeability to water $<$ 10 millidarcies, and (3) volume increase with curing. Brookhaven National Laboratory found that rapid-setting, temperature-driven cement could be formulated by mixing conventional bentonite mud with ammonium polyphosphate, borax, and magnesium oxide [42]. Significant compressive strength was developed by such admixtures in less than 2 h when sufficient concentrations of the magnesium oxide accelerator were used, and the setting time decreased with increased temperature. Furthermore, the material expanded approximately 15% upon setting. These setting characteristics were ideal for plugging major-fracture loss zones, but more control over the setting process was necessary to ensure that the cement would not set up inside drill pipe during field application.
- Better cement placement: Sandia National Laboratories developed a drillable straddle packer (DSP) [43] as a way to improve the effectiveness and reduce the cost of a typical cement treatment by controlling the cement flow into the loss zone and by reducing dilution of the cement caused by other wellbore fluids flowing into the loss zone. An assembly on the end of the drill string carries two

fabric bags that straddle the loss zone and provide zonal isolation. The bags are inflated with cement and seal against the wellbore wall, thereby forcing most of the cement to flow into the loss zone. After pumping a specified volume of cement, the straddle packer assembly is disconnected from the drill string and left in the wellbore while the drill string is tripped out of the hole. The packer assembly is constructed of drillable materials: aluminum, fiberglass, and, in some applications, CPVC plastic – after the cement sets, the DSP is drilled out and the operation resumes. This device was successfully tested in a full-scale wellbore and complete design drawings are contained in the reference, but it was never commercialized.

- Polymeric grout: The concept of using polyurethane grout instead of cement to seal fractures was investigated in the 1980s but early efforts were not successful [44]. Recent encouraging laboratory work and the growing use of polyurethane grouting in civil engineering projects [45], however, stimulated new interest in this technology. An opportunity to evaluate polyurethane grout in the field came with a DOE grant to Mt. Wheeler Power that required reopening a well near Rye Patch NV. This well had been temporarily abandoned after 20 cement plugs had failed to cure lost-circulation problems, but a prototype grouting apparatus, combined with DTRC, was successful in sealing a loss zone approximately 6 m in length and allowing the well to be reopened [46]. The polyurethane grout used in the Rye Patch well is not suited for higher geothermal temperatures, but other polymeric grouts have been developed [47] that can withstand 260°C for 8 weeks.

Despite the demonstration of methods described above, familiarity with cementing practice and ready availability of the equipment and materials mean that it is still the dominant method of formation sealing today.

Well Control

Well control, in general, has to do with controlling the flow of drilling fluids and formation fluids out of the wellbore. If the hole advances into a fractured or permeable stratum where the pore pressure is higher than the static head of the drilling fluid, the formation fluid will flow into the wellbore – this is called a "kick" – and that flow must be controlled. If control of that flow is lost, then the resulting disaster is a "blowout" which, at the least will be very expensive and, at worst, can result in loss of life, equipment, and the drill rig.

The primary method of detecting a kick is to compare measurements of the drilling fluid inflow and outflow; if outflow is greater, there is a kick, if inflow is greater, there is lost circulation. Traditional methods of measuring these flows have been a stroke counter on the mud pumps (a volumetric calculation gives fluid inflow) and a paddle meter on the return line (a flat vane extends into the mud returns such that the angular displacement of the paddle indicates flow rate). Each of these techniques has inaccuracies: pump efficiency (and therefore displacement per stroke) varies with wear and clearances on the pumps, and the paddle meter can be influenced by any number of variables [48]. Development has shown that better methods (magnetic or Doppler flow meters for inflow and rolling float meter for returns) are available [49], and if well control is expected to be an issue, these methods should be investigated.

The apparatus that controls a kick and potential outflow at the wellhead is called the blowout preventer (BOP) or blowout prevention equipment (BOPE). The BOP stack comprises three types of device to shut off the wellbore and prevent fluid flow out of it: annular preventers, pipe rams, and blind rams. The basic function of each is to shut off the wellbore, but they operate in slightly different ways.

- Annular preventer: This is an inflatable bladder that seals around drill pipe, casing, drill collars, or irregularly shaped components of the drill string. It usually has the lowest pressure and temperature ratings of the stack components.
- Pipe rams: These are two sliding gates, each with a semicircular cutout, that come together from each side of the drill pipe. The hole in the center fits and seals around the outside diameter of the drill pipe.
- Blind rams: These are also sliding gates, but there is no hole in the center; they are used when the drill pipe is out of the hole.

Below the BOP stack, two-valved lines (called the choke and kill lines) are connected to the wellhead so

that fluids can be either released from or pumped into the wellbore as part of the well-control process. There will usually be detailed regulatory requirements for the BOPE (see the California manual [50], for example, which is also an excellent reference for information on BOPE) but the critical factors are to make sure that the BOP pressure rating is adequate and that all the elastomer seals in the equipment are qualified for high temperature. One of the primary well-control techniques for geothermal drilling is simply to pump cold water down the well, so it is also important to make sure an adequate water supply is available.

In contrast to oil and gas wells, which are often overpressured and where those pressures are controlled by weighted drilling fluids, geothermal wells most often are under-pressured. This means that the formation pressure is *less* than the drilling fluid head, which is the effect that causes lost circulation, as discussed in a previous section. There are exceptions such as wells in Cooper Basin, South Australia, with wellhead pressures of approximately 35 MPa [51] but the principal issues in geothermal well control usually involve unexpected steam flow. This can be caused by drilling into a formation that is at much higher temperature, and circulating the hot fluid up the wellbore, or much higher pressure than predicted, such as an event that occurred in Hawaii [52], or by sudden, major lost circulation. Any of these events, can drop the drilling fluid level to the point that its static head no longer exceeds the saturation pressure at the formation's temperature, and either the drilling fluid or formation fluids flash into steam. Unexpected steam flow in permeable formation that is not completely sealed by casing is particularly dangerous, because steam can begin to flow up the outside of the previous casing string, eventually destroying the casing's integrity and often causing loss of the drill rig [53].

As in many contexts, prevention of a problem is more efficient than a cure. A number of methods are available to estimate the wellbore temperature profile and warn that a problem may be near: comparison of drilling fluid inflow and outflow temperatures, maximum-reading thermometers either run just above the bit or lowered through the drill pipe on a wireline, or onboard logging tools that can transmit temperature data in real time. Although none of these is guaranteed to provide early warning of a potential kick, it is always important to know as much as possible about the downhole environment.

Having discussed above the problems of steam flow in the wellbore, however, it should be noted that in reservoirs with a dry (superheated) steam resource, such as the Geysers, the production interval is drilled with air to avoid formation damage and plugging [54]. This means that the drilling returns include produced steam from the reservoir. The top of the wellbore is closed by a "rotating head" that seals around the drill pipe, while allowing it to rotate and move downward. The gaseous returns are sent through a manifold called a "banjo box" below the BOP but above a wellhead valve, and then to the "blooie line," which exhausts a distance away from the drill rig and where the returns receive chemical treatment for H_2S abatement. This is very similar to the technique called "managed pressure drilling" in oil and gas reservoirs, where it has been discovered that productivity is much improved if drilling fluid has not been forced into the formation by excessive downhole pressure.

Well control can be a complex topic, but it is clearly critical to a successful drilling operation. Well-control procedures should be part of well planning, so that the proper actions will be established and crews will be familiar with them when drilling begins. It is essential that rig crews be trained to react quickly and appropriately to an unexpected event that might jeopardize the well.

Completions and Cementing

In drilling terminology, a well's *completion* refers to the combination of casing, casing accessories, and cement that allows the well to produce. Casing accessories can refer to perforated or slotted liners in the production zone, internal or external packers, or the hardware necessary for multilateral wells that have more than one leg feeding into the production casing.

Cementing

As described in the Drilling Overview, casing has been traditionally cemented in place by pumping a calculated amount of cement into the casing, placing a movable plug on top of the cement, and then displacing the plug downward with drilling fluid. This

forces the cement to flow out the bottom of the casing and up the annulus between the casing and wellbore. In most oil and gas wells, the casing is cemented in place only at the bottom, with a completion fluid between the balance of the casing and the wellbore wall, but geothermal wells must have a complete cement sheath from bottom to surface [55]. This cement has two important functions: to give the casing mechanical support under its sometimes-intense thermal cycling between production and shut-in, and to protect the outside of the casing from corrosion by in situ fluids.

This implies that geothermal cements should have high bond strength to the casing and should be impermeable, but it is also very advantageous for the cement to be lightweight (at least compared to conventional cement, which has a specific gravity of approximately 1.6). Light weight is important because of the oft-encountered lost circulation described above. If the formation's pore pressure will not even support drilling fluids, then it is impossible to lift a column of normal-weight cement back to the surface when casing is cemented in place. One solution to this problem is foam cement, which has gas injected into it, in the same way as drilling fluid is aerated to make it lighter. Recent experience with difficult wells in California [56] and Hawaii [57] has also shown that reverse circulation foam cementing, where the cement is pumped down the annulus and flows back up drill pipe from the bottom of the casing, has several advantages.

If cement returns have not reached the surface in a conventional cement job (i.e., there is an uncemented annulus around the top of the casing), then some method must be used to cement this remaining volume. The most common method is to pump cement, under pressure, into the top of the annulus, which will fracture the formation down to the top of the existing cement. If the cement has reached as high as the top centralizer, then a "top job," which usually means that small-diameter lines (tremie lines) are inserted into the annulus and cement is pumped into them to fill the annular volume, can be performed. The risk in this is that liquid (water or drilling fluid) will be trapped between the upper and lower volumes of cement (see below in *Completions*), so all possible precautions should be taken to avoid this. If the resources are available, the annulus can be dried with steam [58] to assure the absence of liquid.

Conventional oil well cements are not only too heavy for many geothermal wells, but are susceptible to attack by acids and by CO_2, both of which are common in geothermal reservoirs and both of which degrade the impermeability and strength of the cement. Historically, the major modification to Portland cement for geothermal use is the addition to standard Class G cement of retardants and approximately 40%, or more, silica flour [59], but this does not eliminate the problem of CO_2 and acid attack. Brookhaven National Laboratory carried out a major research program on geothermal cement, intended to mitigate or eliminate these effects. The R&D effort comprised: characterization of cements then used in geothermal environments [60, 61], the extension of hydrothermal cements to higher operating temperatures [62], and the development of new materials such as phosphate-bonded cements [63], polymer cements [64], and other new compositions [65].

BNL worked with cost-sharing industry partners (Halliburton, Unocal, and CalEnergy Operating Company) toward the specific goal of a lightweight cement with outstanding resistance to acid and CO_2 at brine temperatures up to 320°C. Reviews of this work before [66] and after [67] 1997 are provided in detailed reports. BNL succeeded in synthesizing, hydrothermally, two new cements: calcium aluminate phosphate (CaP) cement and sodium silicate-activated slag (SSAS) cement. The CaP cements were designed as CO_2-resistant cements for use in mildly acidic (pH $\sim$ 5.0) CO_2-rich downhole environments. The SSAS cements were designed to resist a hot, strong acid containing a low level of CO_2. Both of these were economical cements because they used inexpensive cement-forming by-products from coal combustion and steel-manufacturing processes. In 1997, Unocal and Halliburton completed four geothermal wells in Sumatra with CaP cement, the first field use of this formulation, and in 1999, Halliburton commercialized it under the name "ThermaLock Cement." SSAS cements have received less attention than CaP, but autoclave experiments in the lab have demonstrated good performance in high-acid environment and, in fact, after undergoing acid damage, the SSAS cement exhibited a self-repairing characteristic. Addition of

fly-ash further improved its acid resistance, so SSAS is promising as low-cost geothermal well cement in high-acid conditions up to 200°C.

Completions

Apart from the requirement for a complete cement sheath around the casing, factors that influence completion design include brine chemistry, multibranch completions, and whether the production interval is stable enough to be open hole or must be completed with a slotted liner.

Brine chemistry can cause two major problems: corrosion and scaling. Brine quality varies greatly, ranging from near-potable in moderate-temperature systems to highly corrosive with high dissolved solids in some high-temperature systems. Many techniques – cement-lined casing, exotic alloys, and corrosion-resistant cement – have been applied to the casing corrosion problem, which is especially severe in the Imperial Valley, California. Shallow and hot, CO_2 bearing zones there drive an external corrosion rate approaching 3 mm of carbon steel per year, so the wells must be abandoned after 10–12 years even after well life is extended by cementing in smaller production strings. Most existing production wells in the Imperial Valley have been completed or retrofitted with titanium casing, which has proved to be cost effective in spite of its very high capital investment (approaching US$3,000/m.)

Scaling, the buildup of mineral deposits both inside the casing and in the production interval, is a problem in geothermal plants around the world [68], and can lead to frequent workovers. In severe cases, untreated scaling can reduce the flow area of casing by half in a matter of months. Casing scale can sometimes be removed with high-pressure jets [69], but scaling in the wellbore often seals the formation and must be drilled out with an under-reamer (an expandable bit that can drill a hole below casing that is larger than the inside diameter of the casing). It is highly preferable to inhibit or prevent scale formation than to remove it, and there are many chemical techniques for this, but discussion of those is beyond the scope of this article.

When casing is cemented, it is also critical that no water be trapped between the cement and the casing, especially in intervals where one casing is inside another, because the water can become hot enough as the well goes on production and heats up that thermal expansion can collapse the inner casing. If the trapped-water location has formation outside it, the fracture gradient is usually low enough to allow the pressure to bleed off into a fracture. These failures can be serious enough that the production casing is imploded and ruptured to the extent that it will reduce production and will provide a path from the formation into the cased hole [70].

Finally, it is necessary to decide whether the production interval of the well is competent enough formation so that it can be left as-drilled (open-hole completion) or whether a slotted liner will be necessary to protect against sloughing or caving into the wellbore. Some indications can be gained from the geologic samples acquired during drilling, or from imaging logs, if available, but this decision is often made based on experience gained from other wells in the same reservoir.

Instrumentation (Drilling and Mud Logging)

This description of instrumentation deals only with those measurements applied to the drilling process, and does not address logging for formation evaluation done during or after drilling. Drilling information comprises both surface measurements – those taken on or around the drill rig – and downhole data retrieved by some type of logging tool that is either lowered into the borehole or forms a part of the BHA.

Surface Measurements

A summary list of desirable measurements for the drill rig was given in the section on rig selection criteria (drilling fluid inflow and outflow rates, drilling fluid inflow and outflow temperatures, standpipe pressure, rotary speed, weight on bit, and torque) but many others exist. The drill rig will have at least a minimum set of instruments that are required for its normal functions, but additional instrumentation and data can be provided by the drilling contractor, the mud-logging company (MLC), or an independent service company. It is most commonly done by the MLC, in conjunction with their primary job of recording the geology of the well, based on the cuttings brought back to surface by the drilling fluid. The MLC also keeps a record of many of the drill rig's operating conditions – a representative MLC, for example, lists all the

following measurements as available, so it is the well planner's responsibility to decide which are necessary.

- Depth
- Block height
- Rate of penetration
- Bit depth tracking while tripping
- On bottom/off bottom
- Hook load
- Weight on bit
- Rotary RPM and torque
- Top drive RPM and torque
- Standpipe pressure
- Casing pressure
- Pump stroke rates
- Pump stroke counters
- Totalized pit volumes
- Individual pit volumes
- Trip tank volumes
- Mud gain/loss
- Mud flow rates
- Mud temperature in and out
- Mud weight in and out
- Mud resistivity in and out
- CO_2 and H_2S

Understanding how to use the measurements is clearly important, and should be part of the driller's training. Some comparisons, such as mud flow rates in and out of the wellbore, have been described previously as diagnostics for lost circulation and/or well-control issues. Others, such as a sudden drop in standpipe pressure as an indication of a washout in the drill string, should be part of training. Many of the measurements made by the MLC can be combined electronically in such a way that an alarm will sound if undesirable conditions appear (e.g., the difference in flow rates becomes large). Virtually, all modern MLCs present and record data in digital format, so that it is easily stored, retrieved, and displayed at multiple locations (including a web site, if desired.)

It is also possible to use longer-term data – torque and weight on bit related to rate of penetration, pump efficiency compared to mud flow rate, temperature change as a function of depth – to establish statistical trends that are a measure of drilling performance or downhole conditions. It is also possible, in principle, to combine surface measurements in a way that provides diagnostics for various drilling conditions and then employs an expert system approach to recommend subsequent action. This has been investigated in the laboratory [71] and some versions of it have been commercialized.

Downhole Measurements

Surface measurements are often ambiguous because there is more than one downhole condition that can produce the same readings at the surface, so downhole measurements are highly valuable in resolving this discrepancy. Downhole measurements can be made in several different ways:

- A sensor package can be lowered into the hole on an electrically conducting cable (wireline), sending back signals in real time as it traverses the wellbore. This method usually requires a specialized wireline truck operated by a logging service company (i.e., this method is relatively expensive and there is some lead time involved unless the truck and crew are on standby at the drill site). Real-time information is advantageous when a very dynamic situation such as drilling is in progress, especially if there is reason to believe that some downhole condition (e.g., pressure, lost circulation, bit dysfunctions) may be harmful, hazardous, or expensive.
- A logging tool with onboard memory can be lowered into the hole on an ordinary cable (slickline), taking readings as it traverses the wellbore, and then brought back to surface where data is downloaded. If real-time data is not required, this method tends to be cheaper and more convenient, because the memory tool can be operated by the rig crew on the rig's hoisting equipment.
- A memory tool can also be part of the BHA, retrieved either when tripping the drill string or by slickline. This method is particularly useful when a slimhole is being drilled with a coring rig, because the memory tool can be part of the core tube and data can be retrieved with every core run.
- An instrumentation package that is part of the BHA can send signals back to the surface through pressure pulses in the drilling fluid. This "mud-pulse telemetry" is most often used for directional drilling, where it provides survey information for steering the hole's trajectory, but it can also send back information on downhole conditions such as

pressure and temperature, or on drilling parameters such as shock and vibration. This method provides real-time data from the bottom of the hole, but has a number of disadvantages, in that it is very expensive, is susceptible to high temperature, cannot operate in aerated mud or air, and has a very low data rate (less than 10 baud).

- Signals can also be sent back to surface from a near-bit instrument package through stress waves in the steel drill pipe. This "acoustic telemetry" is reasonably rugged, has a higher data rate than mud pulse (above 20 baud), can operate in any drilling fluid, and has been commercialized by a company in Canada [72].

All of this technology is very mature for the oil and gas industry, but high temperature is a barrier for much geothermal work. Although other parts of a downhole instrumentation package (e.g., seals, the wireline cable head, and sensors) become more difficult in high temperatures, electronic components are the principal challenge. Commercially available electronic components are generally rated at only about 85°C (This is a "guaranteed" operational temperature, although selected components will operate at higher temperatures), unsuitable for use in geothermal environments, so there are three choices: (1) develop electronic components that can withstand higher temperatures, (2) shield conventional components from the high-temperature environment, or (3) use a combination of (1) and (2).

Electronic components can be protected from high temperature by enclosing them in a thermal flask, or Dewar. A Dewar functions like a Thermos bottle, with an evacuated volume between concentric shells providing insulation for the components inside. Like a Thermos bottle, a Dewar in a hot well will eventually (the length of time that the Dewar will protect the electronics is a function of the wellbore temperature, power dissipation requirements of the electronics package, conductivity of the Dewar, and the heat sink inside the package. For typical geothermal applications, the operating envelope is 6–16 h) allow the components inside to heat up to a point at which they may fail. Dewars provide only temporary protection and are expensive and fragile, but even when using high-temperature electronics, they will give the logging tool additional life. Almost all logging tools, both wireline and memory, used in geothermal environments are protected by Dewars.

Electronic components that can operate, unprotected by thermal flasks, at geothermal temperatures, are the ultimate goal. Two technologies – silicon-on-insulator (SOI) and silicon carbide (SiC) – approach that goal. SOI semiconductors can operate virtually indefinitely [73] at 300°C; SiC semiconductors above 450°C – well above existing electronic packaging technology. Some SOI electronic components have been commercially available for several years [74], and a basic suite of SOI-based logging tools is commercially available now.

Of the many measurements that can be made by logging downhole, by far the most useful for drilling purposes is temperature. Apart from the clear necessity to know whether the hole is approaching a geothermal resource, temperature logs can clarify a number of other drilling situations.

- Logs can provide warning if any temperature-limited downhole equipment (including drilling fluid) is approaching its limit.
- If a lost-circulation zone appears during drilling, logs can often define its location (it is not always at the bottom of the hole).
- Logs can guide the amount of retarder to add to cement before cementing casing.
- Because cement has an exothermic reaction as it cures, logs can locate the top of the cement column if returns do not reach the surface.
- For an injection test in a potential production zone, logs can identify fracture locations.
- Logs can usually identify favorable (impermeable) zones for setting packers, if that is part of the test program.

This is only a sample of the applications that logs can have and, for the cases cited above, real-time data is not critical, so memory tools would be quite adequate. These examples indicate the versatility of temperature logs, so having this capability as a standard part of the drilling program is highly useful.

Future Directions

The future direction of geothermal drilling is, in many ways, undefined. This uncertainty stems from the multiple development scenarios that can be envisioned for the industry. It is widely believed that enhanced geothermal systems (the EGS concept is described in detail elsewhere

in this encyclopedia but, in general, it means injecting fluid into one well or set of wells, forcing that fluid to gain heat by circulating through fractures in the hot reservoir, and then returning it to the surface through another well or wells. Unlike conventional hydrothermal resources, EGS wells do not produce in situ fluids) (EGS) will provide the bulk of new geothermal capacity, worldwide, but many aspects of EGS development are unresolved. Resource location, reservoir creation, and reservoir management will all be different when applied to EGS than is the case in conventional hydrothermal practice, and these differences could well drive drilling research and development in a new direction compared to past R&D for hydrothermal resources.

Costs and risks may also follow a different pattern with EGS. It is well known that geothermal wells cost more than oil and gas wells of comparable depth, and that drilling costs increase more than linearly with depth. Costs for deep geothermal wells, however, do not increase as rapidly with depth as costs for deep oil and gas wells [36]. There are, in general, four ways to reduce well cost: eliminate "trouble" costs, improve the efficiency of standard operations, introduce new and more efficient operations, or change the well design [75]. Because the "average" EGS well is expected to be considerably deeper than the "average" hydrothermal well, however, the focus of cost reduction may shift among these priorities.

Regardless of the directions that drilling research and EGS development may follow, it is still likely that the geothermal drilling market will remain so small, relative to the oil and gas market, that most innovation in geothermal drilling will derive from technology used in the oil patch. Given that assumption, it is useful to look at several drilling methods and technologies that have gained wide acceptance in the oil and gas industry but have been applied sparingly, if at all, in geothermal wells. The following section describes these technologies, summarizes their advantages (with focus on the geothermal context), and discusses the barriers to their use in geothermal drilling.

Drilling with Casing (DWC)

The casing can be used as the drill string, rotating to turn a bit and advancing with the hole as it gets deeper, so that it is already in place when the hole reaches desired depth. There are two basic ways that the bit can be attached to the casing: it can be semipermanently mounted, so that it can be dropped off the end of the casing at final depth, or can be drilled through for passage of a subsequent casing string; or it can be mounted on a drilling assembly that is retrieved either by wireline or drill pipe when the bit needs to be changed, or when the hole is at design depth. If a retrievable bit is used, then it must be small enough to pass through the casing's inside diameter; therefore, it must use an under-reamer to cut the diameter that is large enough for the outside of the casing couplings and the annulus for the drilling fluid return flow.

The casing must always be rotated by a top drive unit, and can be connected to the top drive by either screwing into the top coupling of the casing or by a fixture that stabs into the top joint of casing and locks to its inside diameter. The top drive circulates drilling fluid through the casing's inside and back up the outside, just as it would with drill pipe. As in conventional use, the top drive also has the ability to circulate continuously, which can be important in geothermal drilling with heat-sensitive downhole tools.

There are several advantages to this technology, as described in the cited reference [76].

- Eliminate costs, time, and problems related to tripping drill pipe – Time to trip drill pipe and handle the BHA is a significant fraction of total time (and cost) on some wells [77], but it is also the case that many problems of well control and hole stability are associated with trips.
- Reduce lost-circulation problems – Drilling with casing (DWC) systems can continue drilling when lost circulation is encountered. The rock cuttings tend to be washed into the fractures or permeable zones, acting effectively as lost-circulation material. The relatively narrow annulus also means that fluid flow rates can be lower than would be used with conventional drilling in the same size hole.
- Gain casing setting depth – The ability to drill through lost-circulation zones, or other weak formations, means that sometimes the casing can reach a greater depth than would be the case with conventional drilling. It is possible, for some well

designs and lithologies, that the casing program could be redesigned to eliminate one string of casing. As shown in Section Well Cost, this is a major saving.

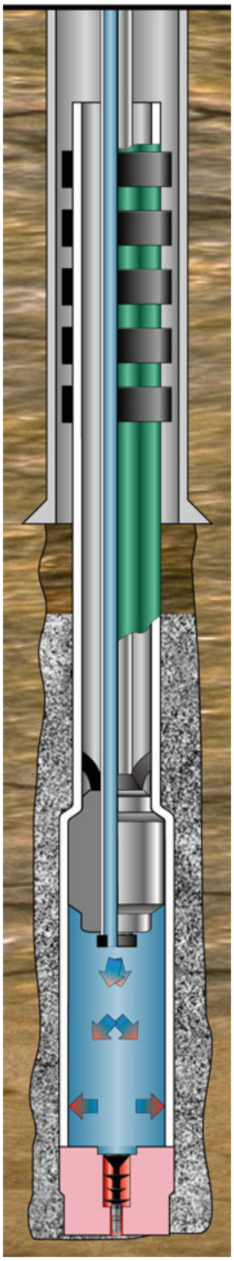
- Improve safety – Handling drill pipe has one of the highest accident incidences in drilling; eliminating this activity means that the crew is exposed to less risk.

Although this technology has been used on hundreds of oil and gas wells, it has seen very limited use for geothermal. There is an issue with retrievable drilling assemblies, because they contain some elastomer components, but the larger factor is hard rock. The cutting structure for most DWC bits uses PDC cutters and, as discussed previously, these cutters have not been notably successful in geothermal formations. Some field experience with hard rock in oil and gas drilling, however, indicates that reasonable performance with roller-cone bits and PDC under-reamers is available [78]. Although a number of questions remain to be answered, this technology appears to have enough potential to warrant further investigation devoted specifically to geothermal drilling.

Expandable Tubulars

As described earlier, casing is installed in successively smaller diameters (see Fig. 3) as the hole gets deeper, so that maintaining the correct diameter in the production zone means having much larger holes and casing at the top of the well. It should also be noted that there is a sizable difference in diameter (10–20 cm) between successive casing strings, so that in the example figure, a 21.6 production interval requires drilling a 102 cm hole at the top. This difference in diameter is required to allow clearance for the couplings on the outside of the inner casing string, to compensate for the fact that the previous casing may not be in a straight hole, and to give sufficient annular area that cement can easily flow through it.

The larger casing sizes and cementing jobs at the top are expensive, however, and drilling larger diameter holes often is slower than drilling a smaller diameter would be. A relatively new technology (first field tested in 1998) makes it possible to run a string of casing with normal clearances and then expand the diameter of the inner string so that the clearance between the two strings is negligible. This diameter increase is implemented by an "expansion cone" in the bottom of the inner casing string (see Fig. 12). Once the hole is drilled, the liner, with the cone assembly in the bottom joint, is made up until the desired length is complete.



Geothermal Resources, Drilling for. Figure 12
Expandable liner (Diagram courtesy of Enventure Global Technology)

Drill pipe is then screwed into the cone launcher assembly and the liner is run into the hole on the drill pipe. Cement is pumped in the normal way (except less volume than would normally be used) and the cone is forced up the liner by a combination of hydraulic pressure beneath it (delivered through the drill pipe) and pulling with the drill pipe. As the liner expands, it forces the cement upward until the liner annulus is completely cemented.

As shown in Fig. 13, using this system (called SET – solid expandable tubulars – by one manufacturer) means that much less clearance between successive casing strings is necessary and, therefore, the upper casings can be smaller for a given production zone diameter than with conventional casing [79].

When considering this system for geothermal drilling, there at least two potential vulnerabilities: the expandable tubulars depend on elastomer seals in some applications, so the temperature rating of the seals is critical; and the inside of the casing has a proprietary coating to ease the cone's passage through the pipe. It is not clear how this coating would be affected by high temperature, but the system has been used in the field [80] at temperatures above 160°C, and tests are under way to qualify seals for use above 250°C in steam-enhanced oil recovery (SAGD).

Another possible use for expandables is to repair or mitigate lost circulation. A section of casing can be expanded into open hole, rather than into a previous casing string and, if the open hole section has been slightly under-reamed, there will be little, if any, loss of diameter because of the patch. Since no cement is used in this treatment, the casing depends entirely on its external elastomers for zonal isolation, making this component especially important for this application. If it can be shown that all components of expandable tubulars can withstand high temperature, then it appears that there are at least two valuable applications for expandable tubulars in geothermal drilling.

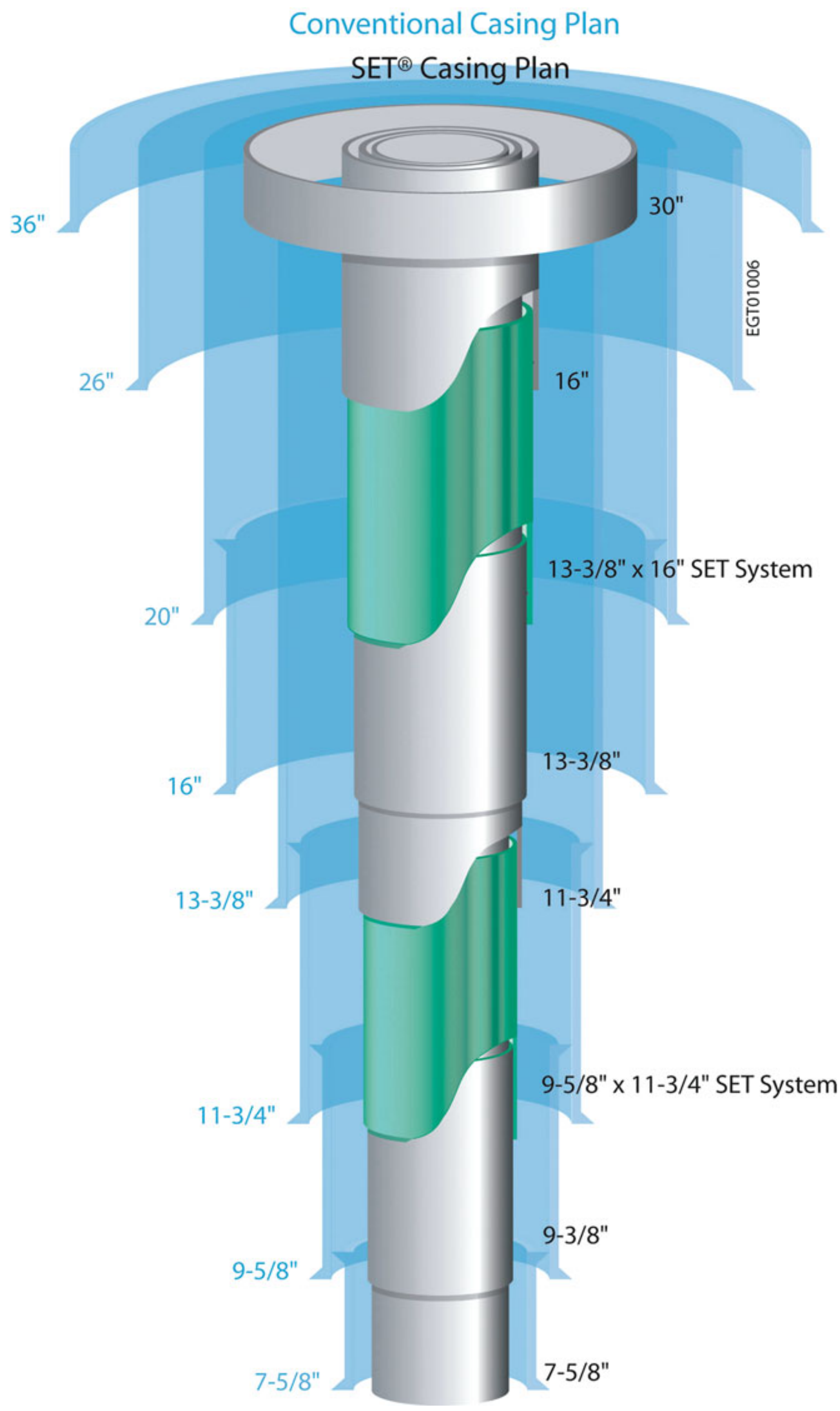
Better Downhole Feedback

Downhole measurements are mentioned in the Instrumentation section, but those were generally measurements related to the state of the wellbore (deviation and trajectory), not real-time data for drilling performance. A few exceptions exist; there is experience with using mud-pulse telemetry to send vibration data uphole [81], but the low mud-pulse data rate limits the applications of these systems. Low data-transmission rates also mean that the downhole sensor package must include a great deal of data processing and, as described previously, keeping the electronics functional at geothermal temperatures is a challenge.

Better real-time data collection, transmission, and interpretation is a high priority in drilling, corroborated by an industry forum [82] that identified this as the most important technology need for reducing flat time (defined as the time the rig is over the hole, with the hole not advancing). The principal barrier to much of this activity has been the lack of a transmission method with adequate bandwidth. In the last decade, however, drill pipe with built-in instrumentation cable has been developed [83]. This pipe has been used at high bandwidth in the field [84], although not at geothermal conditions, and it offers a very promising opportunity for expanded use of real-time downhole data.

The list of measurements that can be made and transmitted is, of course, very large but they fall into three general categories:

- Improve drilling performance – One of the most common causes for poor bit performance, especially with PDC bits, is excessive shock and vibration. Sandia National Laboratories developed a high-data-rate downhole sensor package to improve PDC performance, and field tests [85] with and without the package demonstrated that it significantly lengthened the life of a PDC bit in hard rock. The primary benefit of the real-time data system was to allow destructive downhole conditions to be immediately recognized and mitigated, but it also showed that surface readings for some parameters (e.g., weight on bit) were much different from the values actually measured near the bit. A later version of this system, modified for high temperature, was run in a geothermal well [86], but it has not been commercialized. Other bit dynamics packages are commercially available, although generally not at high bandwidth.



Geothermal Resources, Drilling for. Figure 13
Comparison of casing diameters between SET technology and conventional casing (Diagram courtesy of Enventure Global Technology)

- Avoid trouble – Aside from the problem of bit failure, many other kinds of trouble (well control, lost circulation, unexpectedly high temperature) can either be avoided or recognized much earlier, allowing more effective treatment, with real-time data.
- Eliminate logging time – With properly configured downhole packages, the well can be logged as it is drilled, eliminating the time (sometimes days) at the end of an interval, or the end of the well, normally required to log it. In some cases, logging could be done with a memory tool rather than with real-time instrumentation, but there is a risk that failure in the logging tool would go undetected until drilling was over.

All of these uses imply high-bandwidth transmission systems and, for geothermal drilling, high-temperature downhole electronics (as well as high-temperature batteries). All of these technologies exist in some form, but they have not yet been put together for geothermal drilling.

For More Information

For more information about the topics in this entry, apart from the extensive references cited, other resources are available. Both the Society of Petroleum Engineers (www.onepetro.org) and the Geothermal Resources Council (www.geothermal.org) provide searchable databases of their own publications that include detailed descriptions of geothermal drilling technology. All of the cited references from *Geothermal Resources Council Transactions* are available through the GRC web site (free to members, nominal charge to nonmembers). Stanford University hosts an annual Geothermal Workshop, and papers from those meetings, as well as from World Geothermal Congress, can be located through http://pangea.stanford.edu/ERE/db/IGAstandard/search.htm. The Office of Science and Technology Information maintains the Department of Energy's Geothermal Technologies Legacy Collection (http://www.osti.gov/geothermal/) and many of the papers cited in this entry are available through that resource. The US Bureau of Land Management provides a summary document describing regulatory requirements for exploration, drilling, production, and abandonment on Federal geothermal leases [87] and The Standards Association of New Zealand has published a 93-page manual that combines regulatory requirements with suggestions on operational practices for drilling, maintenance, repair, and abandonment [88]. Finally, the oil-field service company Schlumberger maintains an online glossary with definitions of many common drilling terms at http://www.glossary.oilfield.slb.com/.

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Geothermal Resources, Environmental Aspects of

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Article Outline

Glossary

Aquiclude A geological formation which will not transmit water and is a barrier to vertical movement of geothermal fluid.

Aquifer A geological formation (or formations) which contains water or geothermal fluid and will allow fluid movement.

Downflow Flow of water down a path of high-permeability such as a fracture or a drillhole.

Enhanced geothermal system (EGS) Also called "hot-dry rock". A form of geothermal development in which heat is extracted from rocks that are hot but have low permeability and often low porosity. The rock is artificially fractured by pumping water into it to form a subsurface heat exchanger.

Epicenter The point on the Earth's surface directly above the hypocenter or focus of an earthquake.

Groundwater Water, generally cold and of meteoric origin, which resides in near-surface aquifers and is often used for domestic and industrial purposes.

High-temperature system A geothermal system, or part thereof, containing fluid having a temperature greater than 150°C. c.f. *Low-temperature system* in which the temperature is less than 150°C. It can also be argued that the temperature limit be 180°C, since this is the temperature required for a self-discharging well in a liquid-dominated field.

Hydrothermal eruption An eruption resulting from a localized increase in steam pressure in near-surface aquifers exceeding the overlying lithostatic pressure, and the overburden is then ejected, generally forming a crater 5–500 m in diameter and up to 500 m in depth (although most are less than 10 m deep).

Hypocenter The point at which an earthquake occurs (i.e., the place of rupture), in three-dimensional co-ordinates (x, y, z) c.f. epicenter (x, y).

Injection (reinjection) The process of returning waste water from a geothermal power station back into the ground. This is generally around the edges of the field and may not be into the production aquifer from which fluid is drawn off to the power station.

Liquid-dominated system A geothermal system, or part thereof, in which the pressure is hydrostatically controlled. c.f. *Steam (vapor)-dominated system* in which the pressure is steam static.

Non-condensible gas A gas present in geothermal fluid which does not become dissolved in the waste water after the fluid has been condensed.

Reservoir The region of a geothermal system from which geothermal fluid is withdrawn, or is capable of being withdrawn.

Permeability A measure of the ability of a geological formation to transmit a fluid.

Waste water Geothermal water from which energy has been extracted and is no longer required. This may be steam that has passed through turbines or a binary plant and been condensed, or separated water.

Definition of the Subject

The Encyclopedia of Environmental Science considers the environment to be "the sum of all external conditions and influences affecting the life and development of organisms" [1] and the Oxford Dictionary defines it as "the set of circumstances or conditions . . . in which a person or community lives, works, develops, etc., or a thing exists or operates; the external conditions affecting the life of a plant or animal" [2].

The term "environment" is therefore generally used in a broad sense to encompass not only physical conditions, but also the cultural and spiritual conditions of people living nearby.

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All sources of energy that are used involve some impact on the environment, either in the process of energy extraction, use or in manufacturing the equipment involved. Key features of the geothermal environment are:

Natural Thermal Features

In many geothermal fields there are beautiful natural thermal features that vary in color and form: geysers, fumaroles, hot springs and pools, silica sinter terraces, mud pools, algal mats, thermophilic plants, and areas of heated ground. They are environmentally important because they are rare on a worldwide basis, and often fragile.

Thermal features are often associated with myths and legends in native peoples culture [3]. For example, the native Maori people of New Zealand have a legend that the thermal areas of NZ were formed when fire gods, summoned from far away and traveling underground, surfaced looking for the person who called them. Many societies that use geothermal energy incorporate it into their ceremonies, for example, in Beppu (Japan) they hold a Hot Spring Festival every year.

Cultural Uses

Bathing in geothermal waters is often claimed to have special medicinal properties, and in New Zealand, geothermal waters are used in the government hospital at Rotorua for the treatment of arthritis and skin diseases. Boiling hot pools are used for cooking: food is placed in a woven basket and lowered into the hot pool – this is still done in Japan and New Zealand, but mainly for tourists. In primitive native societies, red and yellow ochre, formed from hydrothermal alteration of rocks, was used to paint the face and body.

Reasons for Preservation

The most compelling reasons why attempts should be made to preserve the environment are:

Self-respect Most human cultures value their surroundings, even to the extent of significantly modifying them to enhance its beauty or desirability. It is generally recognized that the destruction of beautiful natural thermal features such as geysers, hot springs, and silica terraces is unacceptable. The famous American philosopher Thoreaux said: "What is the use of a house if you have not got a tolerable planet to put it on?" [4].

Self-preservation Few advanced living organisms will significantly alter or destroy their surroundings because this is likely to threaten their continued existence as a species.

Maintaining Heritage The natural environment is a heritage, inherited from preceding generations, and it is the responsibility of the present generation to pass it undamaged to future generations.

Economic Effects Changing the environment can have negative economic effects. In the case of geothermal development, the destruction, loss, or modification of beautiful natural thermal features can badly affect tourism, which is often a major source of revenue and employment.

To Meet National and International Obligations In most countries, industrial development (including geothermal) is contingent on the developer obtaining a permit (from a regulatory authority) that involves assessing the impact the development may have on the environment and these are difficult to obtain if significant environmental effects are predicted. Preservation of the environment is also of international concern: 21 of 27 Principles proclaimed by the 1992 United Nations Conference on Environment and Development (Earth Summit) refer specifically to the environment.

Introduction

Use of geothermal energy may have some environmental impacts, most of which are associated with the exploitation of high-temperature liquid-dominated geothermal systems for electric power generation. The majority of these impacts, however, can be avoided or minimized with appropriate techniques.

Possible Environmental Impacts and Their Causes

Impact of Access and Field Development Destruction of forests and vegetation resulting from

construction of road access to drilling sites can lead to landslides and soil erosion, especially in tropical areas with steep hillsides and high, and occasionally intense, rainfall. The mud resulting from such erosion can choke waterways and inhibit aquatic life. Such effects can extend for large distances downstream, even as far as the coast where fishing industries may be affected.

Effects of Drilling Operations Drilling operations are generally noisy and accompanied by fumes from large diesel engines that drive the drill string and generators that provide electricity to the site. Drilling is generally a continuous (24-h, 7-day) operation, and at night powerful lights are used to illuminate the drill pad area. It may take 1–3 months to drill a deep well (1–5 km deep). The impacts of such operations on people living nearby can be severe, especially at night.

Disposal of Waste Drilling Fluid Drilling involves using a thixotropic fluid ("mud") to provide hydrostatic pressure to prevent formation fluids from entering into the well bore, cooling the drill bit, bringing up drill cuttings, and suspending the drill cuttings, while drilling is paused and the drill string is brought in and out of the hole [5]. The mud is generally a mixture of water and clays such as bentonite, together with additives such as barium sulfate (barite), natural and synthetic polymer, asphalt and gilsonite. Other chemicals (e.g., Potassium formate) are often added to achieve various effects such as controlling viscosity, shale stability, enhancing the drilling rate, and cooling and lubricating the equipment. Deflocculants, such as anionic polyelectrolytes (e.g., acrylates, polyphosphates, lignosulfonates, or tannic acid derivates), are frequently used to reduce viscosity of the drilling fluid. If drilling encounters a highly permeable formation and fluid is lost then bridging agents such as calcium carbonate or ground cellulose are added. If some of these chemical agents are released into natural waterways they can kill aquatic life and result in groundwater contamination.

Mass Withdrawal

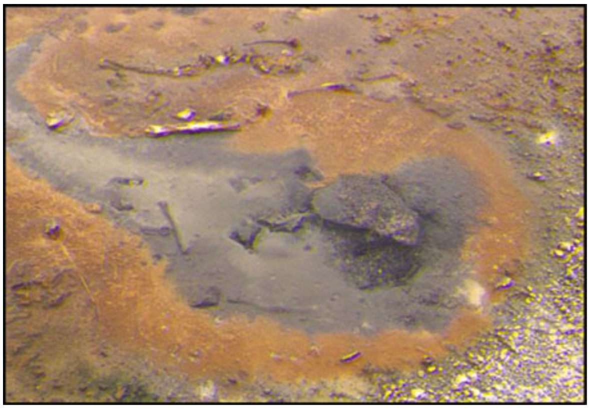
Large-scale exploitation of liquid-dominated, high-temperature geothermal systems involves the withdrawal of large volumes (and hence mass) of geothermal fluid from the ground which, if not corrected for, may cause:

Pressure Declines in the Reservoir Withdrawal of large volumes of geothermal fluid are associated mainly with electric power generation. After passing through the power plant the fluid withdrawn (condensed steam and separated water) is usually injected back into the ground, however, the injection wells are generally located away from the production wells to reduce the chances of the cooler-injected water returning to the production wells and reducing the temperature of production fluids. Even if all the waste liquid is injected, there may be mass loss (up to 30% of that withdrawn) associated with evaporation of condensate from ponds where the water is cooled before injection and from the discharge of non-condensible gases into the atmosphere from the power station. A major consequence of the mass loss from parts of the field is often the formation of a two-phase (steam + water) zone in the upper part of the reservoir in the vicinity of the production wells, and as production continues this zone increases in size and the pressures decrease (both in and below this zone). At Wairakei (New Zealand), the deep (liquid phase) pressures declined by about 0.3 MPa (three bar) during discharges associated with exploratory drilling, and a further 2 MPa (20 bar) during the first 10 years of production, although subsequent pressure declines were less than 0.5 MPa (five bar) and pressures have risen since 1997 [6]. Pressure declines in the reservoir, as a result of mass withdrawal and net mass loss, are an important cause of environmental changes at or near the surface.

Degradation of Thermal Features In their natural, unexploited state many high-temperature geothermal systems are manifested at the surface by thermal features such as geysers, fumaroles, hot springs, hot pools, mud pools, sinter terraces, and thermal ground with special plant species (Figs. 1–4). Often these features are of great cultural significance [3], as well as being important tourist attractions. The thermal features result from the (upward) leakage of boiling geothermal fluid from the upper part of the reservoir, through overlying cold groundwater, to the surface.

Historical evidence shows that natural thermal features have been affected, often severely, during the development and initial production stages of most

Geothermal Resources, Environmental Aspects of. Figure 1
Beehive Geyser, Yellowstone National Park, USA



Geothermal Resources, Environmental Aspects of. Figure 2
Hot spring, Norris Geyser Basin, Yellowstone National Park, USA

Geothermal Resources, Environmental Aspects of. Figure 3
Morning Glory hot pool, Yellowstone National Park, USA

Geothermal Resources, Environmental Aspects of. Figure 4
Minerva Terraces, Yellowstone National Park, USA

high-temperature geothermal systems. At Wairakei (New Zealand), nearly all the thermal features in the Waiora and Geyser Valleys (including more than 20 geysers) have died or been significantly reduced (Fig. 5, [7]). At Ohaaki (New Zealand), the level and temperature of water in the Ohaaki Pool declined soon after exploration drilling and reservoir testing began, but has been restored by discharging some of the warm waste water from the power plant into the pool [8]. At Tongonan field (Philippines) flow from hot springs decreased after production began [9]. Such effects are not confined to liquid-dominated systems. At Larderello (Italy), where the original natural activity consisted of numerous steam and gas jets, activity has now largely ceased. At The Geysers (USA), there has been a decrease in the flow from hot springs since exploitation began.

The decline in thermal features appears to be associated with a decline in reservoir pressure. As the pressure declines, so also does the amount of geothermal fluid reaching the surface and hence the thermal features decline in size and vigor. If pressures fall further then the features may die and the flow may reverse with cold groundwater flowing down into the reservoir; once this situation has occurred it may take a long time to resurrect the features. To reduce the possibility of this occurring, injection is undertaken to keep reservoir pressures as high as possible.

Geothermal Resources, Environmental Aspects of. Figure 5
Champagne Cauldron in Geyser valley at Wairakei, New Zealand, before (*left*, painting by T. Ryan) and after 20 years of development (*right*). Arrows point to the same rock promontory

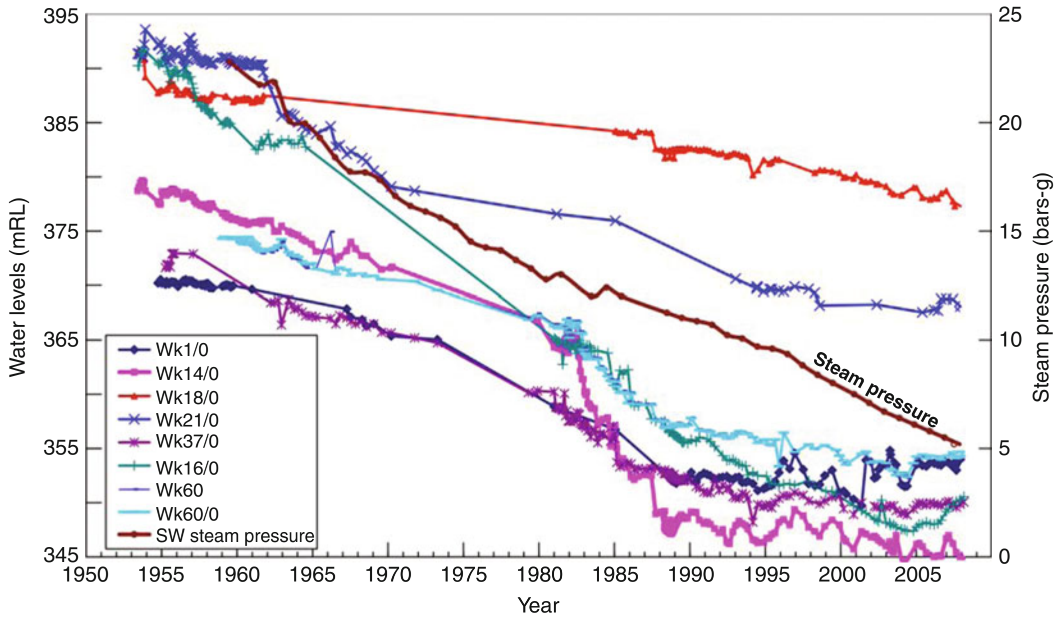
Depletion of Groundwater Most high-temperature geothermal systems are overlain by a cold groundwater zone. If exploitation of the system results in a large pressure drop in the reservoir, this groundwater may be drawn down into the upper part of the reservoir in places where there are suitable high-permeability paths (such as faults). If the lateral permeability of the rocks in the groundwater zone is low then a downflow may result in a drop in the groundwater level. For example, at Wairakei, a localized drop of more than 30 m in groundwater level has occurred associated with an area of cold downflow (Fig. 6, [10]).

Downflows, and resultant groundwater level changes, may also occur as a result of breaks in the casing of disused wells [11]. Such downflows may have flow rates of up to 100–150 t/h.

Ground Deformation Withdrawal of fluid from an underground reservoir can result in a reduction of formation pore pressure which may lead to compaction in rock formations having high compressibility and result in subsidence and horizontal movements at the surface. Such ground movements have also been observed in groundwater reservoirs [12, 13] and petroleum reservoirs [14, 15], and can have serious consequences for the stability of pipelines, drains, and well casings. If the geothermal field is close to a populated area, then subsidence could lead to instability in dwellings and other buildings.

The largest recorded subsidence in a geothermal field (15 m) is in part of the Wairakei-Tauhara field (New Zealand) [16]. Here the subsidence has caused: compressional and tensional strain on pipelines and lined canals, deformation and breaking of drill casing, tilting of buildings and the equipment inside, breaking of sealed road surfaces and alteration of the gradient of streams (Fig. 7, [17]). However, the greatest subsidence rates are confined to small areas (called "bowls") and have decreased since reservoir pressures have stabilized (Fig. 8). In the central part of the bowl there is compressional deformation that may manifest itself as pressure ridges, and on the edges there is tensional deformation that may manifest itself as cracks in the ground (Fig. 9, [16]).

Ground movements have been recorded in other high-temperature geothermal fields in New Zealand (Table 1), at Cerro Prieto (Mexico) [18], Larderello (Italy) [19], and The Geysers (USA) [20, 21].



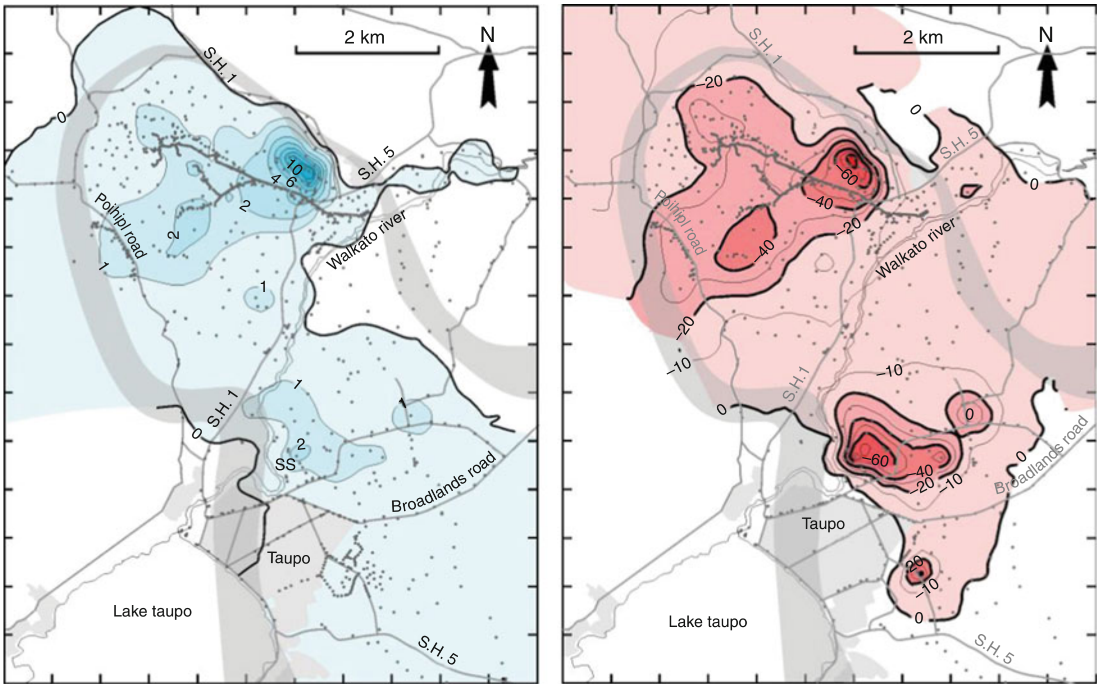
Geothermal Resources, Environmental Aspects of. Figure 6
Changes in level of groundwater in shallow monitor holes at Wairakei (Taken from [10])

Geothermal Resources, Environmental Aspects of. Figure 7
Ponding of the Wairakei Stream near the center of the main subsidence bowl at Wairakei, New Zealand, due to change in the gradient of the stream bed

Ground Temperature Changes The formation and expansion of a two-phase zone, in the early stages of exploitation of a liquid-dominated geothermal system, can also alter the natural surface heat flow (heat loss). Steam is much more mobile than water; it can move through small fractures that are impervious to water and can move much more quickly through larger fractures. The generation and movement of steam can therefore result in increased heat flow and increased ground temperatures, so that some vegetation may become stressed or killed, generally to be replaced by other, thermally tolerant, species. At Wairakei, heat loss from natural thermal features was about 400 $MW_{thermal}$ prior to the start of exploitation in 1958, increased to a peak of nearly 800 $MW_{thermal}$ by the mid-1960s, and has since declined to about 600 $MW_{thermal}$ (Fig. 10, [27]). Most of this increase was associated with increased thermal activity in the Karapiti Thermal Area, which is situated 3 km south-west of the main production borefield. The increase has been attributed to steam, associated with lateral expansion of the steam zone resulting from pressure decreases, rising to the surface up narrow fissures that were previously impervious to water. However, the increase in heat flow has resulted in an increased number of fumaroles, which has enhanced the visitor experience of tourists to the area.

Waste Liquid Disposal

Most geothermal energy developments bring fluids containing dissolved minerals to the surface in order



Geothermal Resources, Environmental Aspects of. Figure 8
Maps of ground subsidence and subsidence rate at Wairakei-Tauhara geothermal field, New Zealand. Left hand map shows total subsidence (m) for the period 1953–2005. Right hand map shows subsidence rate (mm/year) for the period 2001–2005. Gray zone indicates electrical resistivity boundary of the field and dots indicate measurement points (Taken from [16]). Note that the greatest subsidence rates are confined to several small parts of the field

to extract some of the heat contained within them. In high-temperature liquid-dominated geothermal fields, the volumes of resultant liquid waste involved may be large: at Wairakei-Tauhara, a medium-sized geothermal power station (156 MW), it is currently about 5,800 m^3/h. For vapor-dominated systems it is less, and for low-temperature systems it is usually much less (e.g., at Chevilly-Larue (France) it is only about 3 m^3/h). After extracting some of the heat, the waste water is generally disposed of by reinjecting it deep into the ground. Surface disposal, such as putting it into waterways or evaporation ponds, may cause more environmental problems than injection because of the dissolved minerals, particularly arsenic, mercury, and boron compounds. The best method of disposal depends on the chemistry of the geothermal fluid. For some high-temperature power plants such as at Nesjavellir (Iceland) the waste water is piped to the city of Reykjavik for district heating and then disposed of into shallow groundwater aquifers, and tests have shown no apparent effects on water chemistry. At Svartsengi power plant the waste water is discharged into the Blue Lagoon, which is a famous tourist attraction in Iceland (Fig. 11). In many cases, the waste water can be used for greenhouse heating, warm water aquaculture, space heating, irrigation swimming pools, and spas before being disposed of at the surface.

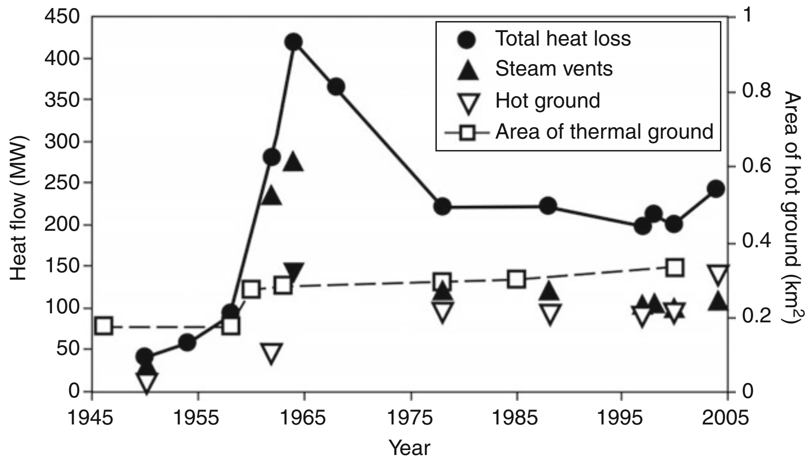
Induced Seismicity Most high-temperature geothermal systems lie in tectonically active regions where there are high levels of stress in the upper parts of the crust; this stress is manifested by active faulting and numerous earthquakes resulting from sudden relief of this stress. Studies in many high-temperature geothermal fields have shown that exploitation can result in an increase (above the normal background) in the number of small magnitude earthquakes (micro-earthquakes) within the field [28–30] (Figs. 12 and 13). Induced seismicity occurs in high-temperature fields (both liquid- and vapor-dominated), but has not been

Geothermal Resources, Environmental Aspects of. Figure 9
Compressional (*left*) and tensional (*right*) deformation features at Ohaaki geothermal field, New Zealand

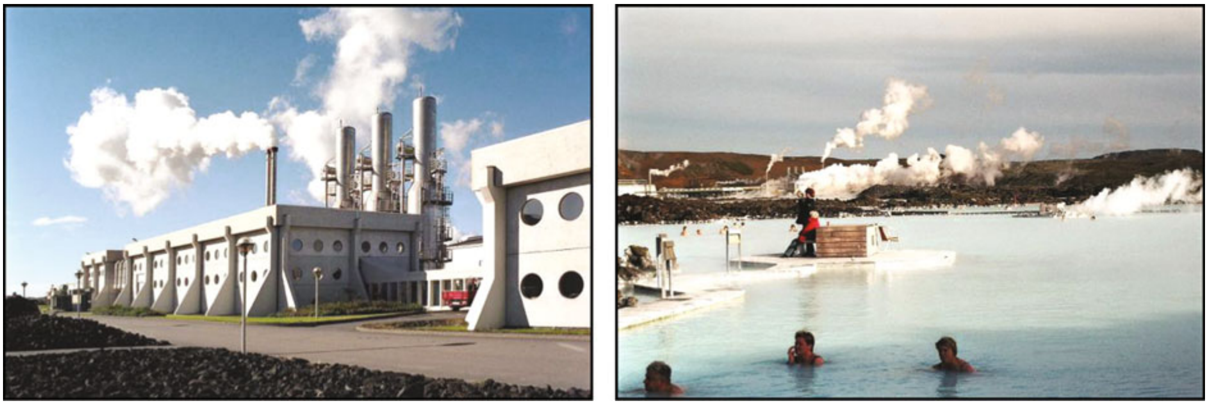
Geothermal Resources, Environmental Aspects of. Table 1 Ground subsidence in some producing geothermal fields. Survey dates are the period for which subsidence has been reported; it is not necessarily the whole production period. Note also that the subsidence rate changes with time and location

Field	Country	Survey period	Max. subsidence (m)	Max. rate (mm/year)	Mass change during survey period		Reference
					Withdrawal (Mt/year)	Reinjection (Mt/year)	
Wairakei	NZ	1955–1995	13.5	470	10–74	0	[16]
Ohaaki	NZ	1988–1998	1.3	400	14–17	10–13	[17]
Kawerau	NZ	1970–1996	0.48[a]	30	10	1.7–2.6	[22]
The Geysers	USA	1977–1996	0.90	47	70	21	[20]
Bulalo	Philippines	1980–1999	0.57	32			[23]
Travale	Italy	1973–1991	0.4	25	2.3–3.9		[24]
Takigami	Japan	1992–1998	<0.02	-	11	8.8	[25]
Hatchobaru	Japan	1990–1996	0.015	-	17.7	20	
Cerro Prieto	Mexico	1994–1997	0.5	120	100	1	[18]
Svartsengi	Iceland	1976–99	0.24	14	0–9		[26]

[a]Corrected for vertical displacement caused by the March 1987 Edgecumbe earthquake



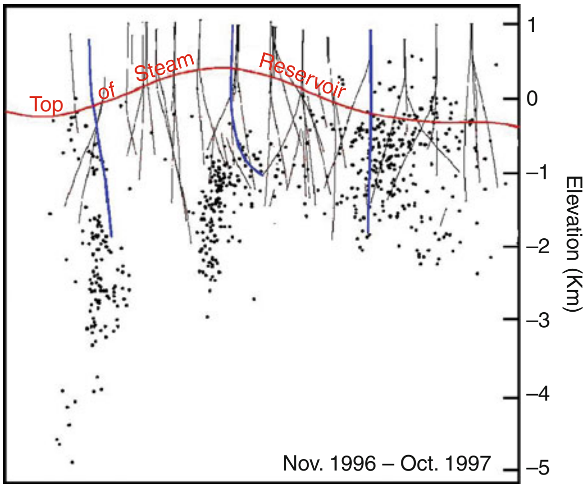
Geothermal Resources, Environmental Aspects of. Figure 10
Changes in heat flow with time at Karapiti thermal area, Wairakei, New Zealand. Note the transient increase in heat flow from steam vents in the early 1960s soon after production began, followed by a decrease and stabilization as steam pressures declined. Figure taken from [27]



Geothermal Resources, Environmental Aspects of. Figure 11
Svartsengi power plant (*left*) and the Blue Lagoon (*right*)

observed in low-temperature fields tapping shallow aquifers. Induced seismicity also occurs in Enhanced Geothermal Systems (Fig. 14) where high wellhead injection pressures are used to stimulate production by creating new fractures and extending existing fractures [31]. To date no serious damage has been caused by such earthquakes, but they may result in a temporary shutdown of the power plant. However, the earthquakes can frighten people (especially those in non-tectonic areas who are unaccustomed to earthquakes); this has happened at Soultz in France, Basel in Switzerland, and Landau in Germany.

It is believed the increase is caused mainly by injection because when injection is stopped the number of small earthquakes decreases, and when it is restarted the number increases [28, 31]. High wellhead injection pressures increase the pore pressure at depth, particularly in existing fractures, which allows movement to suddenly release the stress and generate an earthquake. However, there are other, secondary mechanisms for



Geothermal Resources, Environmental Aspects of. Figure 12
Cross section through The Geysers field (California, USA) showing locations of earthquakes (*black dots*) during a 12-month period. Injection wells are shown in blue. Earthquake hypocenters and wells within 2000 ft (610 m) of the section line have been projected onto the cross section. Note that the earthquakes may extend to depths greatly below the bottom of some injection wells (Taken from [29])

induced earthquakes. Cool injected water can cause contraction of fracture surfaces leading to slight opening of the fractures, reducing static friction and triggering slip on a fracture already near failure. Also, volume changes associated with production and injection may cause perturbation in local stress conditions leading to seismic slip in a similar manner to "rockbursts" in mines as the surrounding rock adjusts to newly created void spaces [31].

Induced earthquakes may number several thousand per year in a geothermal field but few are felt, although a small number of earthquakes may reach (Richter) Magnitude 4. Detailed studies show that the induced micro-earthquakes cluster (in space) around and below the bottom of injection wells, and so the effects at the surface are generally confined to the field [32, 33].

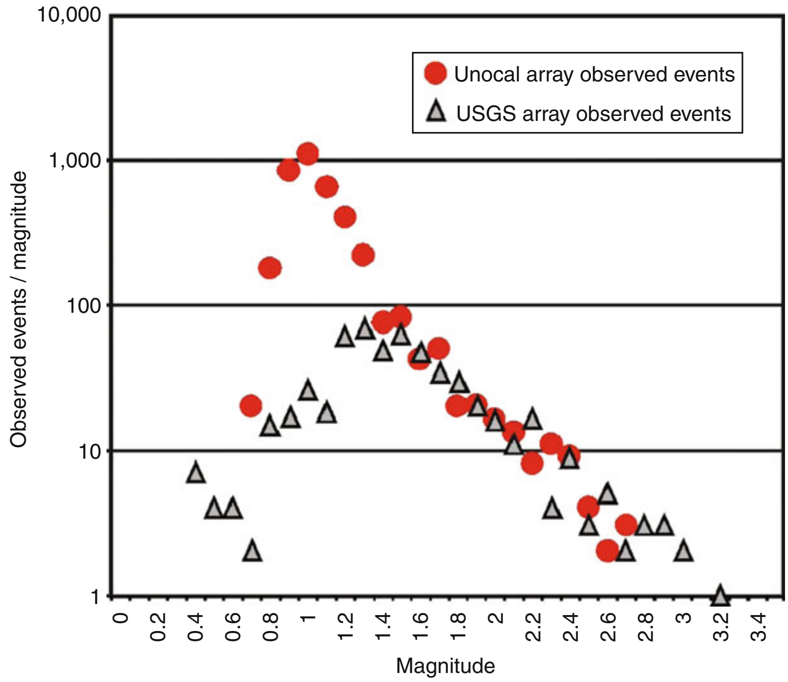
During injection to improve an EGS reservoir at a depth of about 5 km beneath the Swiss city of Basel, an earthquake of magnitude 3.4 was triggered on 8 December 2006. This event caused damage to property, and the developer's insurance paid out damages of about 7 million CHF. Recent probabilistic modeling of the seismic risk [34] (IGA, 2010) has indicated the likelihood of 40 million CHF of property damage and a 15% probability that damages could exceed 600 million CHF if development continued. While the risk of the geothermal project to cause bodily harm is low, that for property damage is considered unacceptable according to Swiss risk criteria and the development has stopped. However, other locations in Switzerland offer a significantly lower seismic risk. The incident at Basel has highlighted the need for thorough evaluation of site-specific seismic risk for future geothermal developments, especially EGS projects in densely inhabited areas.

Effects on Living Organisms If hot geothermal waste water from a standard steam-cycle power station is released directly into an existing natural waterway the localized increase in water temperature may kill fish and aquatic plants near the outlet; therefore, the water is generally passed through cooling ponds and mixed with cold water before being released. Release of untreated mineralized water into a waterway can result in chemical poisoning of fish, and also birds and animals that reside near the water because some of the toxic substances move up the "food chain."

Contamination of Groundwater Release of waste water into cooling ponds or waterways may result in shallow groundwater supplies becoming contaminated and unfit for human use, so care must be taken that the sides and bottoms of such ponds are sealed.

Waste Gas Disposal

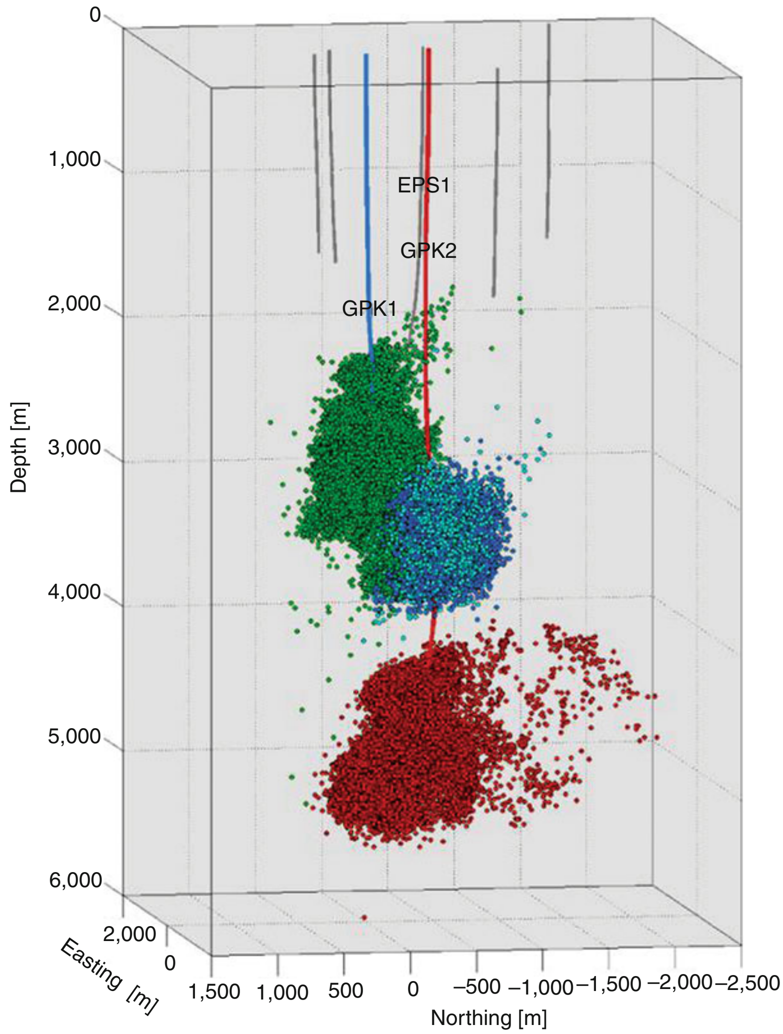
Gas discharges from low-temperature systems are minor and do not usually cause significant environmental impacts. In high-temperature geothermal fields, power generation using a standard steam-cycle or hybrid plant may result in the release of non-condensable gases (NCG) and fine solid particles (particulates) into the atmosphere [35]. In vapor-dominated fields where waste fluids are injected, non-condensable gases in steam will be the most important discharges from an environmental perspective. The NCG emissions are mainly from the gas exhausters of the power station, often discharged through a cooling tower. Gas and particulate discharges



Geothermal Resources, Environmental Aspects of. Figure 13
Plot of frequency against magnitude for microearthquakes in The Geysers field, California, USA for a two-year period (1996–1998). Figure taken from [29]. Note the logarithmic increase in numbers of events as magnitude decreases. The apparent decrease in number of events below about M = 1.3 for the USGS array is because detection of all very small magnitude events ($M < 1$) was not possible with the equipment used, i.e., M = 1.3 is the effective recording threshold. Similarly for the Unocal array the effective recording threshold is about M = 1.0

during well drilling, bleeding, cleanouts and testing, and from line valves and waste bore water degassing are usually insignificant. The concentration of NCG varies not only between fields but can also vary from well to well within a field, thus changes to the proportion of steam from different wells may cause changes in the amounts of NCG discharged.

Gas concentrations and compositions cover a wide range, but the predominant gases are carbon dioxide (CO_2) and hydrogen sulfide (H_2S), together with small amounts of ammonia, mercury and boron vapor, and hydrocarbons such as methane. In some fields, up to 30% (by weight) of the geothermal fluid is NCG. However, although these amounts appear large they are relatively small compared with fossil fuel power stations: the amount of H_2S emitted from a geothermal power station (average 0.03 g/kWh) is less than 2% of that from equivalent size coal- and oil-fired power stations (9.23 and 4.95 g/kWh, respectively). In high-temperature geothermal fields, measured direct CO_2 emission from the operation of conventional power or heating plants is widely variable, ranging from 0 to 740 g/kWh, but averages about 120 g/kWh (weighted average of 85% of the world geothermal power plant capacity) [36]. This is much less than that of 915 g/kWh from a coal-fired plant (35% efficiency), 760 g/kWh from an oil-fired plant (35% efficiency), or 315 g/kWh from a combined cycle gas plant (60% efficiency). In Enhanced Geothermal Systems, power plants are likely to be designed as closed-loop circulation systems, with no direct emissions; only if boiling occurs within the loop may some NCG emission occur. Geothermal power plants are also environmentally friendly with regard to the minor NCG: a coal-fired power plant produces the following kilograms of emissions per MWh as compared to a geothermal power plant: 4.71 versus up to 0.16 for sulfur dioxide, 1.95 versus 0 for nitrogen oxides, and



Geothermal Resources, Environmental Aspects of. Figure 14
Clusters of earthquakes resulting from different injection tests at the Soultz EGS, France. Note how the earthquakes cluster around the bottom of the injection wells

1.01 versus 0 for particulate matter [37]. Hydrogen sulfide is routinely treated at geothermal power plants, and converted to elemental sulfur.

In low-temperature fields (<100°C), direct CO_2 emission from geothermal fluid is about 0–1 g/kWh depending on the carbonate content of the water. If the extracted geothermal fluid is passed through a heat exchanger and then completely re-injected (such as in a closed-loop pumped system), then CO_2 emission is nil to negligible.

Carbon dioxide occurs in all geothermal fluids but is most prevalent in fields in which the reservoir contains sedimentary rocks, and particularly those with limestones. Carbon dioxide is generally the most abundant NCG (>90%). It is colorless and odorless, and is heavier than air so it can accumulate in topographic depressions where there is still air. It is not highly toxic (c.f. hydrogen sulfide) but at high concentrations can be fatal due to alteration of pH in the blood. There is some evidence that in high-temperature fields, the amount of CO_2 discharged (per unit mass withdrawn) decreases with time as a result of degassing of the deep reservoir fluid. When examining the CO_2 emissions from geothermal power plants it is

necessary to consider what would be emanating from the ground naturally (e.g., from fumaroles) in the vicinity of the plant. A strong case can be made for subtracting the natural background emission rate pre-development from the rate being released by the operation of the geothermal development. This is particularly relevant to the Larderello field in Italy where there has been a noticeable and measurable decrease in the natural release of CO_2 from the ground as a result of the geothermal power development on the field [36].

The main effects of release of non-condensible gases, together with water vapor from the cooling circuits, are local microclimatic effects such as fog. However, CO_2 need not be released directly into the atmosphere. It may be captured, purified of other gases (especially H_2S), and used to enhance plant growth in greenhouses growing vegetables. Studies have shown that as CO_2 concentration is increased from a normal level of 300 ppm to levels of approximately 1,000 ppm, crop yields may increase by up to 15% [38]. Another use of geothermal CO_2 is in carbonated drinks – at Kizildere power plant, Turkey, the NCG is scrubbed of H_2S, and the CO_2 recovered provides around 80% of the CO_2 used by the country's soft drinks industry.

Catastrophic Events

Hydrothermal Eruptions Hydrothermal eruptions have occurred at several high-temperature geothermal fields. These are small, shallow-sourced, steam and soil eruptions that generally result in craters 10–50 m in diameter and 5–20 m deep (Fig. 15). Material ejected from the craters may be deposited up to several hundred meters away. At present they cannot be reliably predicted, however, several causes have been identified that increase the likelihood of an eruption [39]. One mechanism assumes an expanding two-phase zone in the reservoir (due to production) that increases steam flow to the surface. Near the surface, an aquiclude may restrict the flow of steam resulting in an increase in the underlying pressures. Also, it has been noted that at Karapiti Thermal Area (New Zealand) the hydrothermal eruptions sometimes follow a long period of low rainfall. During long dry periods, the amount of water in the near-surface aquifer is reduced and further increased heating and steam

Geothermal Resources, Environmental Aspects of. Figure 15
Aerial view of hydrothermal eruption craters at Karapiti thermal area, Wairakei, New Zealand. The white lines are wooden boardwalks that allow tourists to walk over the area safely

flow occurs. If a period of heavy rainfall then occurs, the permeability of the ground near the surface is quickly reduced by the rain, so that the steam cannot escape and pressures can increase to the point where the overlying rocks cannot contain the pressure and an eruption occurs. Another mechanism involves hydraulic fracturing, allowing a release of non-condensable gases and rapid decrease of the boiling point of hot water close to the surface. A third mechanism is a reduction in the lithostatic pressure by removal of the overburden, either naturally by landslides or by man-made excavations. There are no countermeasures available except to maintain reservoir pressures thus minimizing steam formation and concomitant increase in heat flow, and to refrain from building on or excavating in active thermal ground.

Blowouts During Drilling Drilling a deep well in a high-temperature geothermal field carries the risk of a blowout – an uncontrolled flow of underground fluid to the surface outside of the well. Although now rare, several blowouts have occurred in the past [40–42]. Common causes of blowouts are failure to adequately cement the well casing to the surrounding rock, or damage to the well casing by earth movement. Blowouts are generally brought under control by directionally drilling a relief well from nearby to

intersect the original well. This allows cement to be pumped into and around the original well to seal it.

Probably the most spectacular geothermal blowout was during drilling of well WK204 at Wairakei in 1960 [42]. A large and expanding crater, venting steam and rocks, quickly formed near the well, and it was fortunate that the drill rig and associated equipment was able to be removed before they were engulfed. All attempts to control the blowout failed. The crater grew to about 70 m in diameter and 20 m deep, then filled with boiling water that periodically geysered. This activity continued for several years and became a tourist attraction known as "the rogue bore." However during 1973, the temperature and level of water in the crater declined and the feature dried up.

Landslides Many high-temperature geothermal fields are in mountainous regions, and geothermal wells are drilled from well pads carved out from steep slopes. There have been a few instances where landslides, triggered by heavy rainfall or inappropriate engineering works, have broken production wells leading to blowouts [42, 43] or have damaged steam pipelines. The most disastrous has been the landslide of 5 January 1991 in Zunil field, Guatemala, when 23 people were killed [43].

Land Use

Visual Impacts A geothermal plant must be located close to the resource, so there is often little flexibility in siting the plant. Geothermal plants generally have a low profile, and need not have a tall chimney such as coal- and oil-fired power plants. However, their visual impact may still be significant because high-temperature geothermal fields are often situated in areas of outstanding natural beauty and in National Parks (e.g., Japan, USA. and New Zealand). Any associated natural thermal features (e.g., geysers and hot pools) may be a tourist attraction or of historical and cultural significance. Undertaking developments in such areas may cause conflict during the processes for obtaining permits for access and to undertake drilling, and even for access to subsurface resources by directional drilling from outside such parks. Despite good examples of unobtrusive, scenically landscaped developments (e.g., Matsukawa, Japan), and integrated tourism/energy developments (e.g., Wairakei, New Zealand and Blue Lagoon, Iceland), land use issues still seriously constrain new development options in some countries. Visual impact may be particularly high during drilling due to the presence of tall drill rigs.

Footprint A measure of optimum land use is the "footprint" occupied by geothermal installations. Taking into account surface installations (drilling pads, roads, pipelines, fluid separators, and power stations), the typical footprint of a conventional high-temperature geothermal power scheme is about 900 m^2/GWh/year (for 30 years), or 160 m^2/GWh/year excluding wells. Low-temperature geothermal plants (excluding wells) would require land use of between 1,400 and 2,300 m^2/MW [44] equivalent to 150–300 m^2/GWh per year. Subsurface geothermal resources accessed by directional or vertical boreholes typically occupy an area equivalent to about 10 MW/km^2. Therefore, about 95% of the land above a typical geothermal resource is not needed for surface installations, and can be used for other purposes (e.g., farming, horticulture, and forestry at Mokai and Rotokawa fields in New Zealand, and a game reserve at Olkaria, Kenya).

Methods of Avoiding or Minimizing Impacts

Good Management Practices

Responsibility for protecting the environment rests with the developer, and specifically with the engineers and managers. Some general principles for protecting the environment are: regular monitoring of the environment; reliance on scientists and engineers to recognize problems; acting before scientific consensus is achieved; confronting uncertainty; including human motivation (short-sightedness and greed); taking a precautionary approach and being prepared for worst-case scenarios. These principles can be encouraged by regulators which provide good environmental strategies (such as avoid, remedy, or mitigate) and sound guidelines.

Good Engineering Practices

Site Investigation and Development The impacts of access roads and field development can be minimized by careful planning and construction of access roads and prompt re-planting of vegetation destroyed. Simple and reliable criteria have been developed to assess slope

instability and the potential for slope failure in the Philippines [45], and here remediation includes construction of benches to prevent landslides and rigid structural barriers up-slope of and over pipework.

Noise Reduction Noise inevitably occurs during the exploration drilling, construction, and production phases of development. Air drilling is the noisiest (120 dBA) due to the "blow pipe effect" where the gases exit, but suitable muffling can reduce this to around 85 dBA [46]. Mud drilling is quieter at around 80 dBA. Diesel engines operating compressors and electricity generators can also produce a low-frequency resonant sound that carries for long distances; this noise can be constrained, to less than 55 dBA during the day and 45 dBA at night, by suitable muffling and confining noisy operations (such as tripping or cementing) to the daytime hours. Construction of screens of sound-absorbing material, such as vegetation, is also used to reduce the impacts of drilling noise. Following drilling, a well is usually discharged to remove drilling debris. Such vertical discharges are very noisy (up to 120 dBA). After this, there is normally a period of well testing; this can be suitably muffled by the use of silencers, but even then the noise is still significant (70 – 110 dBA). The well is then put on "bleed" where the noise is around 85 dBA reduced to 65 dBA if the "bleed" is led to a rock muffler [46]. Drilling is generally a continuous 24-h/day operation and the effects of using powerful lamps to light the work site at night are reduced by temporary screens and careful placement of the lamps. Modern drilling techniques involve using minimal amounts of fluid and recycling as much as possible.

Injection Changes to thermal features are associated with declines in production reservoir pressures and it appears that the best way to prevent or minimize changes to these features is to minimize any reduction in reservoir pressures by undertaking injection. This will also minimize any changes in groundwater level and temperature, and avoid waste liquid contaminating groundwater. Deep injection also reduces the effects of waste liquid disposal on living organisms. However, it may be necessary to keep injection pressures to a minimum to minimize induced seismicity.

Induced seismicity may be reduced if injection is reduced or halted when the seismicity reaches pre-determined levels. In 2003, a trial was carried out at Berlin Geothermal Field, located in a tectonically active area, which used pressurized injection in an attempt to improve fracture permeability. A calibrated real-time "traffic light" control system [47] was established to reduce or stop injection operations if the levels of vibration (peak ground velocity) from injection-induced seismicity exceeded acceptable levels (normal background = "green," significant felt events = "orange," and damaging events = "red").

Engineering to Overcome Ground Movements Little can be done to prevent or minimize ground deformation, except to maintain reservoir pressures. Experience suggests that subsidence can be halted, but it is difficult to reverse by increasing reservoir pressure because of the great weight of rock overlying the formation that has compacted. The effects of deformation on pipelines is reduced by mounting the pipelines on rollers, but experience at Wairakei shows that even with such assistance sections of pipe need periodically to be removed or installed to maintain the pipeline network. Equipment that is sensitive to level is generally mounted on an adjustable base.

Plant Design Suitable design of power stations employing active monitoring systems will minimize the effects of non-condensible gas discharges and reduce microclimatic effects (e.g., suitable placement of cooling towers and gas discharge vents). If induced seismicity is likely then all structures in the field should be earthquake resistant.

Regulations

Most geothermal developments are controlled and monitored by independent regulatory authorities, such as central, regional, or local government, and they issue (to developers or users) permits or consents which ensure that the best environmental practices are followed [48–51]. This generally involves preparation of an Environmental Impact Report (EIR) before development begins; consideration of that report by officials, experts, and the public; granting of permits subject to restrictions; setting up of a monitoring program and measurements taken regularly; and periodic review of the monitoring data and renewal of the permits. This is not entirely altruistic because if severe environmental

damage occurs it is generally government that has to take ultimate responsibility for the problem.

Economic Measures

Royalties or User Charges One method of encouraging use of a geothermal resource in an efficient and sustainable manner is to charge users for the amount of energy taken. A good example of how implementation of user charges reduced wasteful practices was in Rotorua city, New Zealand [52]. Here, especially during summer, some individual well owners were taking geothermal fluid and not using it, but passing the hot water directly to waste at the surface instead of shutting down their well. Introduction of user charges, and closure of poorly performing wells and equipment, persuaded many of these owners to combine and operate a single well in a sustainable manner, with injection. Since the introduction of the charges the net amount of fluid withdrawn has decreased from about 30 kt/day to less than 10 kt/day, and water levels in the shallow thermal aquifers have risen.

Bonds Another economic measure that can be effectively used to protect the environment and encourage sustainable development is the requirement for a developer to deposit a large refundable bond that is forfeited if environmental damage occurs. Interest on the bond money, less an amount to cover taxes and inflation, may be returned annually to the developer. Although the damage may not be able to be rectified by money, the potential loss of a large amount of money may keep a company more focussed on the environment and the consequences of its actions. Such a system is effective when there is the suspicion that a development company will not be able to meet its obligations either through lack of expertise or financial problems. Bonds are particularly effective with public companies where the profits, share value, and bonuses of the managers may be adversely affected by loss of the bond. However, to date, this approach has not been used in the geothermal industry; it is more common in the mining industry where developers are transient.

Future Directions

The worldwide need for sustainable energy sources means that the exploitation of geothermal energy will continue and even accelerate in the next few decades. Although a few geothermal developments have had serious environmental effects, such as at Wairakei, most of these cases were before the dynamics of geothermal systems was understood. The causes of most of the environmental effects have since been recognized and countermeasures are employed as part of permitting. International scientific efforts, under the auspices of the International Energy Agency (IEA), to devise methods of extracting geothermal energy with the minimum of environmental effects were started in the late 1990s and will continue.

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Global Wind Power Installations

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Article Outline

Glossary

Clean development mechanism Clean development mechanism is the flexible mechanism under Article 12 of the Kyoto Protocol with the purpose to (1) assist non-Annex I Parties in achieving sustainable development, (2) contribute to the ultimate objective of the UNFCCC (United Nations Framework Convention on Climate Change), and (3) assist Parties included in Annex I achieve compliance with their quantified emission limitation and reduction commitments. Annex I Parties refer to industrialized countries that were members of the OECD (Organization for Economic Cooperation and Development) in 1992 plus countries with economies in transition (the EIT Parties), including the Russian Federation, the Baltic States, and several Central and Eastern European States.

Installed capacity Installed capacity is the total MW of operational generation plant of a given technology.

Offshore Wind power plant installed in a marine environment.

Offshore wind developments Offshore wind developments are wind power plants installed in shallow waters off the coast.

Onshore wind developments Onshore wind developments are wind power plants installed on land.

Definition of the Subject

Wind power has been utilized for over 3,000 years to aid with human activities. Although it was predominantly used as mechanical power at the beginning, gradually, with industrialization, the focus shifted to the use as electrical power. With the arrival of the oil price shock in the early 1970s, the use of wind energy as electrical power started to gain more focus, and since the end of the twentieth-century, wind energy has become one of the most important sustainable energy resources. The installation of wind power production capacity is growing at a rapid pace, doubling every 3 years, and is expected to continue growing in the future, providing around 20% of the worlds' power needs by 2030. With strong growth in on- and offshore developments in Europe, and rapid market expansions in the rest of the world, it is imperative that the knowledge which is currently concentrated in a few countries be spread, as implications on research, education, and electric utilities all around the globe are significant. This is the main purpose of this chapter, to present an overview of the relevant areas as well as providing links to further readings and related organizations.

Introduction

The power of the wind has been utilized for at least 3,000 years. Until the early twentieth-century, wind power was used to provide mechanical power for pumping water or for grinding grain. At the beginning of modern industrialization, however, the use of fluctuating energy sources such as wind was gradually replaced by more stable power sources such as fossil-fuel-fired engines and electricity.

With the first oil price shock in the early 1970s, interest in the power of the wind resurfaced. This time, however, the main focus was on wind power providing electrical energy rather than mechanical energy. By converting wind energy into electrical energy, it became possible to provide a reliable and consistent power source, particularly when used with other energy technologies as a backup, via the electrical grid.

The first wind turbines for electricity generation had already been developed at the beginning of the twentieth-century; however, technology started improving step by step since the early 1970s. By the

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end of the 1990s, wind energy reemerged as one of the most important sustainable energy resources. During the last decade of the twentieth-century, worldwide wind power capacity doubled approximately every 3 years, and in the past decade between 2000 and 2010, it has sustained a compound annual growth rate of over 20% [1]. The cost of wind-generated electricity has fallen by a factor of about 4 during the last 25 years, and some even claim that wind power prices have now converged with the prices of electricity from gas, coal and nuclear plants [2]. Experts in the field predict that the cumulative capacity will be growing worldwide starting off at 27% in 2010 and gradually declining to 5–9% by 2020, supplying up to around 20% of the world's power needs by 2030 [3].

Wind energy technology itself has also moved also very fast toward new dimensions. As can be seen from Table 1, at the end of 1989, a 300-kW wind turbine with a 30-m rotor diameter was state-of-the-art. But only 10 years later, 1,500-kW turbines with a rotor diameter of around 70 m were available from many manufacturers. The first demonstration projects using 2-MW wind turbines with a rotor diameter of 74 m were installed before the turn of the century. 2–5-MW turbines are now in 2010 commercially available, and prototypes of 6–7.5-MW wind turbines are currently being installed. The largest turbine under development is a 15-MW turbine planned for offshore use in 2020 [6].

Global Wind Power Installations. Table 1 Development of wind turbine size between 1985 and 2010

Year	Capacity (kW)	Rotor diameter (m)
1985	50	15
1989	300	30
1992	500	37
1994	600	46
1998	1,500	70
2002	3,000	90
2006	5,000	112
2010	7,000	126
2015	10,000–15,000	150

Source: DEWI [4] and different editions of [5]. 2015 values estimated based on various research proposals

This fast development of the wind energy market as well as of the technology has large implications on research, education, and on professionals working for electric utilities or the wind energy industry. It is important to mention that more than 73% of the worldwide wind capacity is installed in only five countries: USA, China, Germany, Spain, and India. Hence, most of the wind energy knowledge is concentrated in these countries. The use of wind energy technology, however, is fast spreading to other areas in the world. Hence, the available information must also be spread around the world, and this is the main purpose of this chapter. However, despite the fact that wind energy has been already utilized for 3,000 years, it remains a very complex technology. The technology involves a combination of technical disciplines, including aerodynamics, structure-dynamics, mechanical, as well as electrical engineering. Due to the complexity of the wind energy technology, it is not possible to cover all related topics in this chapter in great detail. The chapter aims rather at presenting an overview of the relevant areas as well as providing links to further readings and related organizations.

Current Status

This section will provide a brief overview of the status of wind energy around the world at the end of the first decade of this century. Furthermore, major wind energy support schemes will be presented.

Wind energy statistics are regularly published by various organizations. Regional or countrywide statistics are often compiled and published by the corresponding wind energy associations. For example, The Spanish Wind Energy Association [7], the German Wind Energy Institute [4], the International Economic Platform for Renewable Energies [8], and the Global Wind Energy Council [9] regularly publish worldwide statistics. Up-to date worldwide statistics are published by Windpower Monthly [5] in the January, April, July, and October editions. The Danish wind energy consultant BTM also publishes an annual wind energy development status report with worldwide statistics and forecasts [10]. The latest World Market Update report published in 2010 provides a very good overview of the current status as well as an interesting future scenario of how to meet 10% of the world's electricity demand with

Global Wind Power Installations. Table 2 Operational wind power capacity worldwide

Region	Installed capacity [MW]				
	End-1995	End-2000	End-2005	End-2009	End-2010
Europe	2,518	12,972	40,898	76,152	86,075
North America	1,676	2,695	9,832	38,383	44,189
Latin America	11	103	212	1,274	2,008
Asia and Pacific	626	1,795	7,878	41,831	61,038
Middle East and Africa	13	141	271	865	1,079
Total world wide	4,844	17,706	59,091	158,505	194,390

Source: 1995 and 2001 January editions of [5], 2006 and 2009 editions of [9], and [13]

Global Wind Power Installations. Table 3 Top-ten new installed capacity 2009

Country	MW	%
China	13,803	36.0
USA	9,996	26.1
Spain	2,459	6.4
Germany	1,917	5.0
India	1,271	3.3
Italy	1,114	2.9
France	1,088	2.8
UK	1,077	2.8
Canada	950	2.5
Portugal	673	1.8
Rest of world	3,994	10.4
Total top 10	34,348	89.6
Total world wide	38,342	100.0

Source: 2009 edition of [9]

wind power by 2020. The World Wind Energy Association's World Wind Energy Report [11] and the IEA Wind Energy Annual Report [12] provide detailed overviews of the research and industry activities and policies in the area of wind energy for various countries.

Global Status

Wind energy has been the fastest growing energy technology since the 1990s in terms of the percentage of yearly growth of installed capacity per technology source. The growth of wind energy, however, is not evenly distributed around the world (see Table 2). By the end of 2010, around 44% of the worldwide wind energy capacity was installed in Europe, a further 31% in Asia and the Pacific, and 23% in North America.

In 2009, more than 38 GW of new wind power capacity was installed around the world (Table 3). This was a surprise for many people in the industry, who expected the financial crisis to put a halt to the record-breaking trend of the growth in wind energy. In fact, the growth rate was 31.7%, the highest rate since 2001. Over a third of the new installations were made by China, more than doubling its installations compared to the previous year, and catapulting itself to second place in total cumulative installed capacity, just ahead of Germany (Table 4). Almost another third was installed in the USA, who maintains its number one position in total cumulative installations. With over 80 countries using wind energy on a commercial basis in the world, wind energy has become an important player in the world's energy markets. Source: 2009 edition of [11].

The top-ten ranking of wind power plant owners and manufacturers in 2009 is shown in Table 5. Leaders in the development of wind power plants are dominated by European companies such as Vestas, Enercon, and Gamesa, which cover 46.7% of total cumulative installed capacity. However, with rapid developments in China, companies such as Sinovel and Goldwind are now breaking into top ranks of the manufacturing industry.

May 26 (Reuters) – China's wind turbine manufacturers are growing fast, challenging the dominance of players such as Vestas and GE.

According to Danish consultants BTM, three Chinese suppliers now rank among the world's top-ten turbine makers.

Following is a list of the top-ten wind turbine makers and their percentage of the global market.

Europe

Between the end of 2005 and the end of 2010, around 33% of all new grid-connected wind turbines worldwide were installed in Europe (see Table 2). A breakdown of installed capacity per country is shown in Table 6. The main driver in Europe for this development was the creation of fixed feed-in tariffs in countries such as Germany and Spain. Feed-in tariffs are defined by the government as a price per kWh that distribution companies have to pay for electricity that is generated from renewable resources and fed into the local distribution grid. For an overview of tariffs, see [14]. Fixed feed-in tariffs reduce the risk of fluctuating electricity prices and therefore provide a long-term secure income to investors.

In Denmark, a market price and premium is used for onshore wind power plants, and bidding processes are used for offshore wind power plants. For onshore wind power plants, this means that a feed-in premium is paid for a certain number of hours of electricity produced by wind turbines at the installed output, and in addition, a refund of a smaller amount is paid for balancing costs of electricity. For offshore wind power plants, potential developers are invited to submit offers for building new wind park projects. Developers bid for the amount of financial incentives to be paid for each kWh fed into the grid by renewable energy systems, and the best bidder(s) is awarded their bid feed-in tariff for a predefined period [15].

Global Wind Power Installations. Table 4 Top-ten cumulative installed capacity 2009

Country	MW	%
USA	35,064	22.1
China	25,805	16.3
Germany	25,777	16.3
Spain	19,149	12.1
India	10,926	6.9
Italy	4,850	3.1
France	4,492	2.8
UK	4,051	2.6
Portugal	3,535	2.2
Denmark	3,465	2.2
Rest of world	21,391	13.5
Total top 10	137,114	86.5
Total world wide	158,505	100.0

Source: 2009 edition of [9]

Global Wind Power Installations. Table 5 Breakdown of global wind turbine manufacturing industry

No.	Company	Country	Newly installed in 2009 (MW)	%	Cumulative (MW)	%
1	Vestas	Denmark	4,766	12.9%	39,705	23.6%
2	GE wind energy	USA	4,741	12.8%	22,931	13.6%
3	Sinovel	China	3,510	9.5%	5,658	3.4%
4	Enercon	Germany	3,221	8.7%	19,738	11.7%
5	Goldwind	China	2,727	7.4%	5,315	3.2%
6	Gamesa	Spain	2,546	6.9%	19,225	11.4%
7	Dongfang electric	China	2,475	6.7%	3,765	2.2%
8	Suzlon	India	2,421	6.5%	9,671	5.7%
9	Siemens wind power	Denmark/Germany	2,265	6.1%	11,213	6.7%
10	REpower	Germany	1,297	3.5%	4,894	2.9%
Total for other companies			7,034	19.0%	26,331	15.6%
Total			37,003	100.0%	168,446	100.0%
Top-ten companies			29,969	81.0%	142,115	84.4%

Source: GWEC, Wind Power (March 2010) and BTM Consult [5, 9, 10]

Global Wind Power Installations. Table 6 Operational wind power capacity in Europe

Country	Installed capacity (MW)	
	End-2005	End-2010
Germany	18,428	27,214
Denmark	3,128	3,752
Spain	10,028	20,676
Netherlands	1,224	2,237
UK	1,353	5,204
Sweden	509	2,163
Italy	1,718	5,797
Greece	573	1,208
Ireland	495	1,428
Portugal	1,022	3,702
Austria	819	1,011
France	757	5,660
Belgium	167	911
Turkey	20	1,329
Poland	73	1,107
Other[a]	550	2,677
Total	40,898	86,075

Source: 2006 January edition of [9] and [13]
[a]Bulgaria, Croatia, Cyprus, Czech Republic, Estonia, Faroe Islands, Finland, Hungary, Iceland, Latvia, Liechtenstein, Lithuania, Luxembourg, Malta, Norway, Romania, Russia, Slovakia, Slovenia, Switzerland, and Ukraine

In the United Kingdom, the approach is based on Fixed Quotas Combined with Green Certificate Trading also known as ROCs (Renewable Obligation Certificates). This scheme enforces fixed quotas for utilities regarding the amount of renewable energy per year they must sell via their transmission or distribution network. At the same time, producers of renewable energy receive certificates for the amount of renewable energy fed into the grid. Utilities must buy these certificates to show that they have fulfilled their obligation of meeting the quota. Similar schemes are used in a number of other European countries, such as Sweden and Norway [1].

No detailed data regarding the average size of the wind turbines installed in Europe is available. However, for single countries such as Germany, data is available as presented in Table 7. This presents the development of the average size of new wind turbine installations in Germany.

Global Wind Power Installations. Table 7 Development of the average turbine size in Germany

Year	Average size of yearly new installed capacity in Germany (kW)
1985	20
1986	45
1987	44.8
1988	66.9
1989	143.4
1990	164.3
1991	168.8
1992	178.6
1993	255.8
1994	370.6
1995	472.2
1996	530.5
1997	628.9
1998	785.6
1999	935,5
2000	1,114
2001	1,278
2002	1,394
2003	1,553
2004	1,696
2005	1,723
2006	1,849
2007	1,888
2008	1,923
2009	2,013
1 HJ 2010	1,985

Source: Various editions of [4] by DEWI

The average size of the yearly installed wind turbines in Germany has increased from 20 kW in 1985 to 1,985-kW in 2010. In 2010, in Germany, 14% of the

total newly installed wind turbines had a capacity under 2-MW, whereas the share of turbines with 2–2.9-MW was 82.8%. A small 3% of the newly erected wind turbines had a capacity exceeding 3-MW. On a European scale, turbines of 2-MW and larger have become virtually standard since 2005 [1].

Several countries now have operational offshore wind power plants in Europe. These include Denmark, Sweden, the UK, the Netherlands, Belgium, Ireland, and Finland (see Table 8). Although significant development only started in the early twenty-first century, the growth has been steady, and it is starting to have an increasing impact on Europe's wind power development. In 2010, the annual installed capacity more than doubled compared to the previous year, taking the total installed capacity from 2,063 MW at the end of 2009 to 2,964 MW at the end of 2010 [9, 20].

There are significant plans backed by the European Commission to increase production capacity in the North Sea and develop an offshore grid, which is expected to reach up to 40 GW of installed capacity by 2020 (2009 edition of [9]).

Further offshore projects are planned particularly in the UK (Greater Gabbard: 504 MW; Sheringham Shoal: 315 MW; Walney Phase 1: 184 MW; Ormonde: 150 MW), Germany (Bard 1: 400 MW; Baltic 1: 48 MW), Belgium (Bligh Bank: 165 MW) and Italy (Tricase: 90 MW) [16].

A summary of the offshore wind power plants in Europe in 2010 is shown in Table 8.

North America

After the wind power boom in California during the mid-1980s, development of wind energy slowed down significantly in North America. In the middle of the 1990s, the dismantling of old wind power plants sometimes even exceeded the installations of new wind turbines, which led to a reduction in the overall installed capacity.

In 1998, a second boom started in the USA. This time, wind project developers aimed at installing projects before the federal Production Tax Credit (PTC) expired on the 30 of June 1999. The PTC added \$0.016–0.017/kWh to wind power projects for the first 10 years of a wind plant's life. Between the middle of 1998 and June 30, 1999, the final day of PTC, more than 800 MW of new wind power generation was installed in the USA, which included between 120 and 250 MW of "repowering" development at several Californian wind power plants. A similar development took place before the end of 2001, which added 1,600 MW between the middle of 2001 and the end of December 2001. Currently, the USA has over 36 GW of installed wind capacity and is leading as world number one in cumulative installed capacity (Table 4 and Table 9). In addition to Texas, major projects have been carried out in the states of Minnesota, Oregon, Wyoming, and Iowa (Table 10).

The typical wind turbine size installed in North America at the end of the 1990s was between 500 and 1,000 kW. The first megawatt turbines were installed in 1999 and since 2001; many projects have used megawatt turbines. At the end of 2009, the typical size was 1,750 kW (2009 editions of [12] and [21]). In comparison to Europe, however, the overall size of wind power plant projects is usually larger. Typical projects in North America are larger than 50 MW, with some projects of up to 200 MW, whereas, in Europe, projects are usually between 20 and 50 MW. The reason for this is the limited space in Europe due to the high population density, especially in Central Europe. These limitations have led to offshore developments in Europe; however, in North America, offshore projects are not a major topic.

The major driver for further wind energy development in several states in the USA are an extension of the PTC as well as fixed quotas combined with green certificate trading, known as the Renewable Portfolio Standard (RPS) in the USA or Renewable Energy Credits (RECs) in the UK. Other drivers are financial incentives, e.g., offered by the California Energy Commission (CEC), as well as green pricing programs. Green Pricing is a marketing program offered by utilities to provide choices for electricity customers to purchase power from environmentally preferred sources. Customers thereby agree to pay higher tariffs for "Green Electricity" and the utilities guarantee to produce the corresponding amount of electricity by using "Green Energy Sources" such as wind energy.

Considering the immense possibilities its wind resources present, Canada is falling somewhat behind the global development of wind energy. Despite this, 2009 marked the best year for Canada's national wind

Global Wind Power Installations. Table 8 Offshore wind energy projects

Name	Year	Capacity (MW)	Hub height (m)	Distance from shore (km)	Water depth (m)
Nogersund, SE	1991–1998	1*0.22	37.5	0.25	7
Vindeby, Baltic See, DK	1991	11*0.45	37.5	1.5	3–5
Lely, Ijsselmeer, NL	1994	4*0.5	41.5	1	5–10
Tunø Knob, Baltic See, DK	1995	10*0.5	43	6	3–5
Dronten, NL	1996	28*600	50	30	1–2
Bockstigen, Baltic See, SE	1997	5*0.55	41.5	4	5–6
Utgrunden, Baltic See, SE	2000	7*1.425	65	8	7–10
Blyth, North See, UK	2000	2*2	58	1	5–6
Middelgrunden Baltic See, DK	2001	20*2	60	1–3	2–6
Yttre Stengrund, Baltic See, SE	2001	5*2	60	5	8
Horns Rev I, DK	2002	80*2	70	14	6–14
Nysted (Rødsand I)DK	2003	72*2.3	90	6–10	6–0
North Hoyle, UK	2003	30*2	67	3–10	5–12
Samsø, DK	2003	10*2.3		3.5	11–18
Frederikshavn, DK	2003	4*	80	0.8	3
Scroby Sands, UK	2004	30*2	60	2.5	2–10
Arklow Bank, IR	2004	7*3.6	74	10	2.5–5
Enova offshore – Emden, DE	2004	1*4.5	100	<1	–
Kentish Flats, UK	2005	30*3	70	8.5	5
Egmond aan Zee, NL	2006	36*3	70	8–12	19–22
Barrow, UK	2006	30*3	75	7	21–23
Breitling, DE	2006	1*2.5		1	2
Lillgrund, SE	2007	48*2.3	68	10	2.5–9
Beatrice, UK	2007	2*5		25	40
Burbo Bank, UK	2007	25*3.6	84	5.2	10
Lynn and Inner Dowsing, UK	2008	54*3.6	80	5–5.2	10
Princess Amalia, NL	2008	60*2	100	23	19–24
Kemi Ajos I + II, F	2008	10*3	88	<1	3
Hooksiel, DE	2008	1*5	90	0.4	2–8
Thornton Bank I, BE	2008	6*5	94	27–30	12–27
Horns Rev II, DK	2009	90*2.3	68	30	9–17
Rhyl Flats, UK	2009	25*3.6	80	8	4–15
Alpha Ventus, DE	2009	12*5	90	43	30
Storebaelt/Sporgø, DK	2009	7*3		2	6–16

Global Wind Power Installations. Table 8 (Continued)

Name	Year	Capacity (MW)	Hub height (m)	Distance from shore (km)	Water depth (m)
Floating Hywind, NO	2009	1*2.3	65	12	220
Robin Rigg (Solway Firth), UK	2010	60*3	80	9.5	>5
Gunfleet Sands, UK	2010	48*3.6	75	7	2–15
Vänern (Gässlingegrund), SE	2010	10*3	90	4	4–10
Rødsand II, DK	2010	90*2.3	68.5	8.8	6–12
Thanet, UK	2010	100*3	70	12–17.7	14–23
Poseidon, DK	2010	0.011*3			

Source: [16, 17, 18, 19]

SE Sweden, *DK* Denmark, *NL* The Netherlands, *F* Finland, *IR* Ireland, *BE* Belgium, *DE* Germany, *NO* Norway

Global Wind Power Installations. Table 9 Operational wind power capacity in North America

Country	Installed capacity (MW)			
	End 1995	End 2001	End 2005	End 2010
USA	1,655	4,275	9,149	40,180
Canada	21	198	683	4,009
Total	1,676	4,473	9,832	44,189

Source: 2005 edition of [9] and [13]

energy market with 950 MW of new capacity being installed. Since 2007, when the ecoENERGY for Renewable Power Program was established, a payment of C$0.01/kWh (before tax) is offered for the first 10 years of a project's life. This program was immensely successful, so much so that the target of reaching 4,000 MW of renewable energy projects by March 31, 2011, was achieved well ahead of schedule. As a consequence, the federal government decided to terminate the program in March 2010, and the future remains uncertain. In addition to the federal scheme, the state of Ontario implemented a feed-in tariff, offering C$0.13/kWh for onshore wind power plants in 2009. With various state governments taking initiative to improve their policy frameworks, substantial growth is expected in the state of Ontario, as well as Quebec, British Colombia, New Brunswick, and Nova Scotia.

Latin America

Despite large wind energy resources in many regions of Latin America, the development of wind-powered electricity is very slow as it can be seen from the figures in Table 11. This is due to the existence of low electricity prices as well as the lack of sufficient wind energy policies. For these reasons, until now, many wind projects in South America have been financially supported by international aid programs.

Argentina, however, introduced a new policy at the end of 1998, which offered financial support to wind energy generation in the form of feed-in tariffs. This initiative triggered a spate of developments until the year 2002, when the economic crisis occurred. With the crisis, most developments stopped, and it was not until 2007 when a new law was established that further development ensued. The federal government in May 2009 announced the intention to revive the former plan for renewable energy development called GENREN, which will serve as a framework to set up a regulation aiming at the promotion of renewable energies. The finalization and efficient application of this plan in conjunction with the National Wind Energy Strategic Plan (PENEE) is expected to reactivate development in the wind industry, with several projects in the range of 20–90 MW already in the pipeline [22].

In Brazil, the government established the "Programa de Incentivo às Fontes Alternativas de Energia Elétrica"

Global Wind Power Installations. Table 10 Operational wind power capacity in the USA

State	Installed capacity [MW]	
	End 2001	October 2010
Texas	1,100	9,712
Iowa	332	3,669
California	1,688	2,814
Oregon	199	2,095
Washington	161	2,036
Illinois	0	1,847
Minnesota	311	1,813
New York	19	1,274
Colorado	58	1,248
North Dakota	2	1,222
Indiana	0	1,130
Oklahoma	0	1,130
Wyoming	140	1,101
Kansas	114	1,026
Pennsylvania	34	748
New Mexico	1	597
Missouri	0	457
Wisconsin	53	449
West Virginia	414	414
South Dakota	3	412
Montana	0	386
Utah	0	223
Maine	0	200
Idaho	0	163
Nebraska	3	153
Michigan	1	143
Arizona	0	63
Hawaii	11	63
Tennessee	0	29
New Hampshire	25	25
Massachusetts	1	17
Ohio	0	9
Alaska	1	8
New Jersey	8	8
Vermont	6	6
Delaware	0	2
Rhode Island	1	1
Total	4,688	36,693

Source: 2002 January edition and 2010 edition of [5]

Global Wind Power Installations. Table 11 Operational wind power capacity in South and Central America

Country	Installed capacity (MW)		
	End-2001	End-2005	End-2010
Argentina	25.7	27	60
Brazil	20	29	931
Mexico	2.2	3	517
Chile	1.3	2	172
Costa Rica	51	71	123
Other[a]	2.8	80	205
Total	103	212	2,008

Source: 2002 of [5], 2002 edition of [12], 2006 edition of [9], and [13]
[a]Colombia, Chile, and Cuba

(PROINFA) with the objective to increase the share of renewable energy through government incentives, providing feed-in tariffs and 20 year contracts with guaranteed demand. In addition to this, a number of government tax incentives and discounts on transmission tariffs have also been implemented. The PROINFA program has been an important step for establishing a stable platform for growth in the wind industry, accounting for up to 95% of the current wind power installations in Brazil. Since December 2009, a new approach has been adopted, where bids are now based on production, where the quantity of energy delivered annually is divided by 12 months to smooth the monthly income, rather than on a feed-in tariff system [23]. The policies in Brazil has brought about rapid growth in wind-capacity installations from 341 MW to

606 MW in 2009, a 78.5% increase, and manufacturing bases opening on its shores (2009 edition of [9]).

Mexico has also seen a rapid expansion in wind energy development in recent years, particularly in the Isthmus of Tehuantepec. The average turbine size in this region is 1,136 kW (2009 edition of [12]). However, until now, the only incentive to build new projects has been income tax credits which allow some expenses associated with wind installation to be deducted from taxable income streams.

Chile is another country with favorable conditions for wind energy development. Wind energy is considered by the law as a nonconventional energy resource, which has been promoted by the Development Agency of Chile (CORFO) and the National Commission of Energy (CNE) since 2005. The development of wind energy projects, especially grid-connected electricity-generation projects, is supported through financial incentives. The development of wind parks in the country is still at an early stage however, and there are no specific programs or policies for wind energy alone [22].

Until now, the typical size of wind turbines was around 300 kW in Latin America. However, with new manufacturing capacity for larger wind turbines being established in Brazil, further development is envisioned for the future. In other Latin American countries, however, it may still be difficult to install large turbines due to limitations in infrastructure, particularly for larger equipment such as cranes. Offshore wind projects are not planned, but further small to medium-size ($\leq$30 MW) projects are under development onshore.

One of the major incentives for developing wind projects in Latin America is the emission reduction certificate crediting scheme through the Clean Development Mechanism. La Ventosa, for example, the largest wind power plant in Mexico, as well as numerous projects in Chile and Brazil have gained additional income benefits through this scheme.

Asia and Pacific

The Asia-Pacific region contributes to 31% of global installed capacity of wind power (see Table 2), mainly due to the strong growth experienced in India and China. This must be attributed to the rapid growth in demand. Refer to Table 12 for a detailed breakdown of installed capacities in each country.

Global Wind Power Installations. Table 12 Operational wind power capacity in Asia and Pacific

Country	Installed capacity (MW)			
	End-1995	End-2001	End-2005	End-2010
China	44	361	1,266	42,287
India	565	1,426	4,430	13,065
Japan	5	250	1,061	2,304
Australia	10	74	708	1,880
New Zealand	2	37	169	506
Taiwan	0	3	104	519
South Korea	0	8	98	379
Other[a]				98
Total	625	2,162	7,879	61,038

Source: 1997 and 2002 editions of [5], 2006 edition of [9], 2008 edition of [11], and [13]

[a]Phillipines, Thailand, Bangladesh, Indonesia, Sri Lanka, Vietnam, and Pacific Islands

India achieved an impressive growth in wind turbine installation in the middle of the 1990s, in what was called the "Indian Boom." In 1992/1993, the Indian government started to offer special incentives for renewable energy investments by guaranteeing a minimum purchase rate as well as a 100% tax depreciation in the first year of the project. Furthermore, a "power banking" system was introduced, which allowed electricity producers to "bank" their power with the utility and avoid being cut off during times of load shedding. In this scheme, power could be banked for up to 1 year. In addition, some Indian States introduced additional incentives, such as investment subsidies. Development of new installations between 1993 and 1997 were rampant, but it slowed down after 1997 due to uncertainties regarding the future of the incentives (Reference: various editions of [5]). In 2008, the Ministry for New and Renewable Energy (MNRE) announced a national generation-based incentive scheme for grid-connected projects under 49 MW, providing an incentive of 0.5 rupees per kWh (0.7 Euro cents/kWh) in addition to the existing state

incentives [24]. This has helped with the development of small- to medium-sized wind power plants, but the tariff is deemed to be too low to have a significant impact on a project's viability. In the absence of a better national framework, some states with Renewable Portfolio Standards or other policies to promote wind generation have introduced feed-in-tariffs for wind generation which are higher than that for conventional electricity.

In China, the wind power industry increased capacity by over 100% in 2009 [25]. Its cumulative installed capacity now ranks second in the world. The main reason for the dramatic increase was due to the new focus of the Chinese government to prioritize wind energy as a measure to diversify its energy mix. A recent study by the China Meteorological Administration showed that the potential for wind power in on- and offshore schemes in China are huge, reaching over 3.5 TW in onshore and 200 GW in offshore [25]. The National Energy Administration of China is currently progressing its plans to capitalize on this resource with targets in six provinces to reach a total of 127.5 GW by 2020, dubbed the "Wind Base" program.

There is also the only offshore wind project outside of Europe in China. The Donghai Bridge Wind Power plant is a 102 MW wind power plant close to the Donghai Bridge in Shanghai constituting 34 Sinovel 3-MW turbines. It started producing and transmitting power to the mainland grid on July 6, 2010, and is the first commercial offshore wind power plant in China [26]. As part of the Wind Base program, the Chinese government is planning the construction of further 7 GW of offshore wind power plants in the province of Jiangsu by the year 2020.

In terms of policies, wind power plants have been eligible for a renewable energy premium which is added to the cost of each kWh of electricity sold since 2006. Furthermore, since 2009 a feed-in tariff has been introduced for wind power, which applies to the entire operation period of a wind power plant. The tariff differs depending on the region's wind resource, and the government is underway to formulate the tariff rate for offshore wind power to be applied to the anticipated growth in the future. Source: 2009 edition of [9].

In Japan, demonstration projects testing different wind turbine technologies dominated the development. At the end of the 1990s, the first commercial wind energy projects started operation on the islands of Hokkaido as well as Okinawa. The interest in wind power is constantly growing in Japan. There also exists direct financial subsidies aimed at tackling the up-front cost barrier, either for specific equipment or total installed wind system cost.

In Japan and Korea, investment in wind projects are driven by an enhanced feed-in tariff in the form of an explicit monetary reward provided for wind-generated electricity, usually paid by the electricity utility, at a rate per kilowatt-hour somewhat higher than the retail electricity rates being paid by the customer. In addition, these countries employ a form of renewable portfolio standard, which mandates that the electricity utility (often the electricity retailer) source a portion of its electricity supplies from renewable energies.

At the end of the 1990s, the first wind energy projects also materialized in New Zealand and Australia. The main driver for wind energy development in Australia was the Mandatory Renewable Energy Target (MRET) which was introduced in 2001. This scheme requires electricity retailers to source specific proportions of total electricity sales from renewable energy sources according to a fixed timeframe. The national MRET scheme is supported by State-run feed-in-tariff schemes. In addition to the MRET scheme in Australia, there is also a green electricity scheme where customers are given the option to purchase green electricity based on renewable energy from the electric utility at a premium price.

Typical wind turbine sizes installed in the Asia-Pacific region is 1.5–2 MW (Reference: 2009 edition of [12]), and with manufacturing plants based in China and India, further development is anticipated, especially in China.

Middle East and Africa

Wind energy development in Africa is very slow as evident from the figures in Table 13. Most projects require financial support by international aid organizations, as only limited regional support exits. Despite this, an increasing number of African governments are becoming aware of the potential of wind energy in their countries and are beginning to set up the necessary

Global Wind Power Installations. Table 13 Operational wind power capacity in Middle East and Africa

Country/ region	Installed capacity (MW)			
	End-1995	End-2001	End-2005	End-2010
Egypt	5	125	145	550
Morocco	0	54	64	286
Tunisia		10	20	114
Other	7	14	42	129
Total	12	203	271	1,079

Source: 1997 and 2002 editions of [5], 2006 edition of [9], 2008 edition of [11], and [13]

[a]Iran, South Africa, Cape Verde, Israel, Lebanon, Nigeria, Jordan, Kenya

frameworks. An example of this is the setup of the first feed-in tariff in South Africa, which is designed to produce 10 TWh of electricity per year by 2013 from renewable resources [27].

Several projects have been developed in Egypt with the support of the government agency for New and Renewable Energy Authority (NREA). Five hundred and forty-five megawatt of installed capacity had been built near the city of Zafarana by the end of 2010, in addition to 5 MW in the Gulf of Zayt. Significant developments are expected in the order of 3,000 MW in the next years. Furthermore, there is also a buildup of industrial activities in manufacturing of wind turbines. Further projects are planned in Morocco as well as in Kenya, Ethiopia, Namibia, Tunisia, and Cape Verde. Source: 2009 edition of [11], [22] and various editions of [5].

The typical wind turbine size used in this region is between 600 and 800 kW. However, in light of the fact that the majority of the African population still has no access to electricity grids, small, decentralized, and stand-alone wind energy systems, in combination with other renewable energies, is expected to play a key role. This process is still in its early stage, however, and the limiting factors remain the lack of access to know-how and to adequate financial resources (2009 edition of [11]).

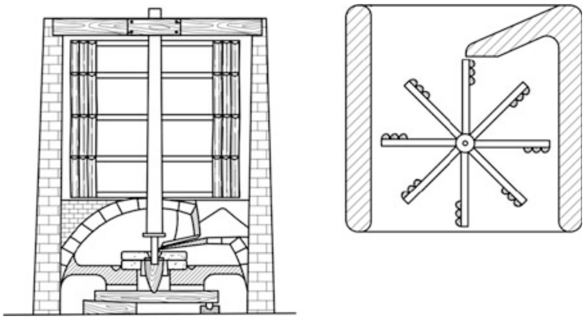
Types of Wind Turbines

Wind energy conversion systems can be divided into those which depend on aerodynamic drag and those which depend on aerodynamic lift. The early Persian (or Chinese) vertical-axis wind wheels (Fig. 1) utilized the drag principle. Drag devices, however, have a very low power coefficient, with a CP.max of around ≈0.16 [28, 29].

Modern wind turbines are predominately based on aerodynamic lift. Lift devices use aerofoils (blades) that interact with the incoming wind. The force resulting from the aerofoil body intercepting the air flow does not consist only of a drag force component in direction of the flow, but also of a force component that is perpendicular to the drag: the lift force. The lift force is a multiple of the drag force and therefore the relevant driving power of the rotor. By definition, it is perpendicular to the direction of the air flow that is intercepted by the rotor blade, and via the leverage of the rotor, it causes the necessary driving torque [28–31].

Wind turbines using the aerodynamic lift can be further divided according to the orientation of the spin axis into horizontal axis– and vertical axis–type turbines. Vertical-axis turbines, also known as Darrieus (Fig. 2) after the French engineer who invented it in the 1920s, use vertical, often slightly curved symmetrical aerofoils. Darrieus turbines have the advantage that they operate independently of the wind direction and that the gearbox and generating machinery can be placed at ground level. High torque fluctuations with each revolution, no self-starting capability, as well as limited options for speed regulations in high winds are, however, major disadvantages. Vertical-axis turbines were developed and commercially produced in the 1970s until the end of the 1980s. The largest vertical-axis wind turbine was installed in Canada, the ECOLE C with 4,200 kW. Since the end of the 1980s, however, the research and development of vertical-axis wind turbines has almost stopped worldwide [28, 29, 31, 32].

The horizontal-axis or propeller-type approach dominates the current wind turbine applications. A horizontal-axis wind turbine consists of a tower and a nacelle that is mounted on the top of a tower.



Global Wind Power Installations. Figure 1
Persian-type windmill. (Kaboldy, Wikimedia Commons)

Global Wind Power Installations. Figure 2
Darriues wind power generator near Heroldstatt, Germany. (W.Wacker, Wikimedia Commons)

The nacelle contains the generator, gearbox, and the rotor. Different mechanisms exist to point the nacelle toward the wind direction or to move the nacelle out of the wind in case of high wind speeds. On small turbines, the rotor and the nacelle are oriented into the wind with a tail vane. On large turbines, the nacelle with rotor is electrically yawed into or out of the wind, in response to a signal from a wind vane.

Horizontal-axis wind turbines typically use a different number of blades, depending on the purpose of the wind turbine. Two or three bladed turbines are usually used for electricity power generation. Turbines with 20 or more blades are used for mechanical water pumping.

The number of rotor blades is indirectly linked to the tip speed ratio, which is the ratio of the blade tip speed and the wind speed. Wind turbines with a high number of blades have a low tip speed ratio but a high starting torque. This high starting torque can be utilized for fully automatically starting water pumping when the wind speed increases. A typical example for such an application is the water-pumping windmill often seen in the midwest USA. Wind turbines with only two or three blades have a high tip speed ratio, but only a low starting torque. These turbines might need to be started if the wind speed reaches the operation range. But a high tip speed ratio allows the use of a smaller and therefore lighter gearbox to achieve the required high speed at the driving shaft of the power generator [28, 29, 31–33].

Apart from the above discussed wind turbine design philosophies, inventors frequently come up with new designs, using some kind of power augmentation, for instance. However, none of these inventions have given sufficient large-scale performances yet. For the current status of power augmentation wind turbines, see [34] and [35].

The Four Wind Turbine Types

Type-I Type-I wind turbines are fixed-speed wind turbines that were introduced and widely used in the 1980s. It uses a squirrel cage asynchronous generator (SCIG), where the rotor is driven by the turbine and the stator is directly coupled to the grid. The rotation speed of this kind of turbine can vary only slightly, between 1% and 2%; therefore, it is effectively at a "fixed speed." There are single-speed and double-speed versions, but the double-speed version is better at adapting to different wind speeds, producing less noise at low wind speeds. Type-I wind turbines typically have limited

voltage control and reactive power control capabilities to support the grid. The stall system is mostly passive stall, inherit to the aerodynamic design of the blades. There are few options for active control besides connecting and disconnecting, especially if there is no blade pitch change mechanism. However, the concept has been continuously improved, for example, in the active stall designs, where the blade pitch angle can be changed toward stall by the control system. Type-I wind turbines make up 15% of the total cumulative European market share and are manufactured by Suzlon, Nordex, Siemens (used to be Bonus), and Ecotecnia [36].

Type-II Type-II wind turbines were commonly used by Vestas in the 1980s and 1990s in Europe and still offered nowadays by Vestas in selected markets as well as by Suzlon. They are equipped with a wound rotor induction generator (WRIG), which has limited variable speed capabilities. Power electronics is used to control the rotor's electrical resistance, which allows both the rotor and the generator to vary their speeds up and down by 10% to cope with wind gusts, to maximize the power quality, and to reduce the mechanical loading on the turbine components, power electronics is also used. Type-II wind turbines also have limited voltage control capabilities to support the grid and are equipped with an active blade pitch control system. Typical Type-II wind turbines are the Vestas models V27, V34, and V47, which make up 5% of the total cumulative European market [36].

Type-III Type-III wind turbines combine the advantages of previous systems with advances in power electronics, producing an improved variable speed capability. It uses a doubly-fed induction generator (DFIG) which has a wound rotor coupled to the grid through a back-to-back voltage source converter that controls the excitation system in order to decouple the mechanical and electrical rotor frequency and to match the grid and rotor frequency. The active and reactive power can be controlled through the use of power electronics, enabling active voltage control. In this type of system, up to approximately 40% of the power output goes directly to the grid, and the window of speed variations is approximately 40% up and down from synchronous speed. Many manufacturers produce Type-III wind generators, including GE, Repower, Vestas, Nordex, Gemasa, Alstom, Acciona Windpower, Suzlon, Bard, and Kenersys. It is the main type of wind turbine in the European market, making up 55% of all installations [36].

Type-IV Type-IV wind turbines are variable speed turbines with full-scale frequency converters that come with the classical drivetrain (geared), in the direct-drive concept (with slow running generator and no gearbox), or in a hybrid version (low step-up gearbox and medium-speed generator). Various types of generators are used for this type of turbine: synchronous generators with wound rotors, permanent magnet generators and squirrel cage induction generators, etc. The stator is connected to the grid via a full-power electronic converter, and the rotor has excitation windings or permanent magnets. Being completely decoupled from the grid, it can provide an even wider range of operating speeds than the Type-II wind turbine and has a broader range of reactive power and voltage control capacities. Type-IV wind turbines are manufactured by Enercon, MEG (Multibrid), GE, Winwind, Siemens, Leitner, Mtorres and Lagerwey, making up 25% of the total cumulative European market [36].

Penetration

At the end of 2009, electricity produced by wind turbines contributed to only 2% of the global electric energy. However, in some countries and regions of the world, wind has become one of the largest electricity sources. The highest shares are seen in countries such as Denmark (20%), Portugal (15%), Spain (14%), and Germany (9%) [2009 edition of [11].

Costs

Over the past 20 years between 1990 and 2010, the capital cost of producing wind turbines has fallen steadily due to economies of scale created by optimization of manufacturing technologies, mass

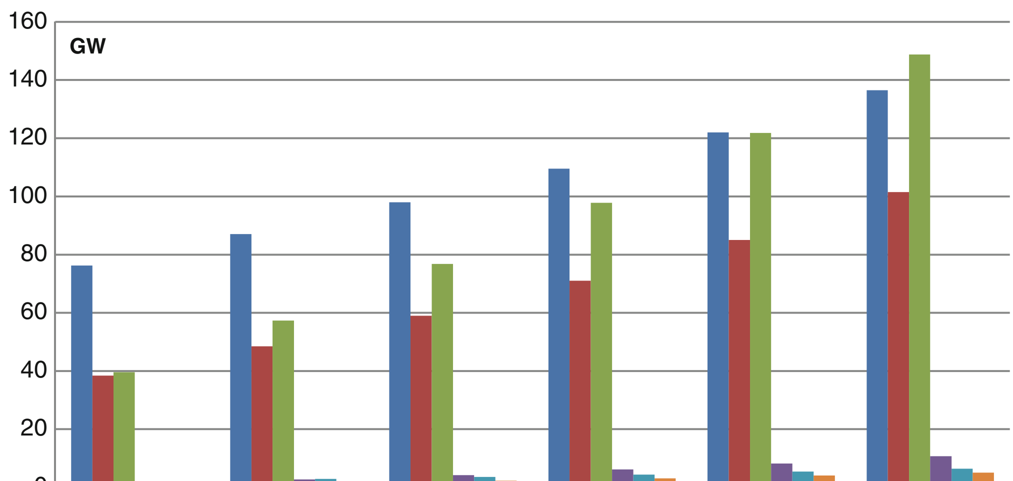
production, and automation [3]. The cost has fallen by a factor of about 4 during the last 25 years between 1985 and 2010, with the general conclusion that costs decrease by some 20% each time the number of units produced doubles.

However, in the years leading up to 2010, particularly since 2006, increasing commodity prices for raw materials such as copper (used in generators), steel (used for towers, gearboxes and rotors), and concrete (used in foundations), rising energy prices, as well as bottlenecks in certain sub-productions have caused the investment cost per MW to increase for new wind power projects (2009 edition of [21]). Although supply chain pressures can be addressed by building new production capacity and establishing new manufacturing bases in countries like China, the industry will have to continue battling with the pressure of rising commodity and energy prices.

Despite these challenges, the cost of wind turbine generators has fallen significantly overall, and the industry is recognized as being in the "commercialization phase," as understood in learning curve theory [37].

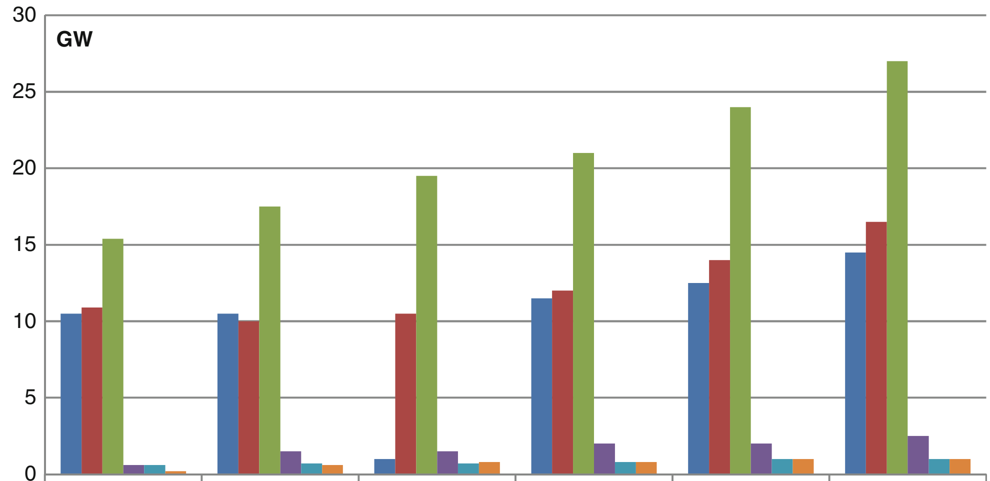
For example, the average capital cost per kilowatt of installed capacity rose from €1,300 in 2007 to €1,350 in 2009. However, it is assumed that it will then fall steadily from 2010 onward to between €1,240 and €1,172 by 2020 and to between €1,216 and €1,093 by 2030 [21].

Given the high up-front costs of wind power projects, large investments of predominantly private but also public funds are expected to flow into the growing wind power markets. This investment will directly benefit regional development by creating jobs in manufacturing, transportation, construction, project development and operation, and maintenance; providing new revenue sources to local landowners such as a farmers or communities; and increasing the local tax base. The value of investment in the future wind energy markets is thus larger than what is visibly obvious at. Besides these



	2009	2010	2011	2012	2013	2014
Europe	76.2	87	98	109.5	122	136.5
North America	38.4	48.5	59	71	85	101.5
Asia	39.6	57.3	76.8	97.8	121.8	148.8
Latin America	1.3	2.7	4.2	6.2	8.2	10.7
Pacific	2.2	2.9	3.6	4.4	5.4	6.4
Middle East and Africa	0.9	1.5	2.3	3.1	4.1	5.1

Global Wind Power Installations. Figure 3
Cumulative market forecast by region 2009–2014 (2009 edition of [9])



	2009	2010	2011	2012	2013	2014
Europe	10.5	10.5	1	11.5	12.5	14.5
North America	10.9	10	10.5	12	14	16.5
Asia	15.4	17.5	19.5	21	24	27
Latin America	0.6	1.5	1.5	2	2	2.5
Pacific	0.6	0.7	0.7	0.8	1	1
Middle East and Africa	0.2	0.6	0.8	0.8	1	1

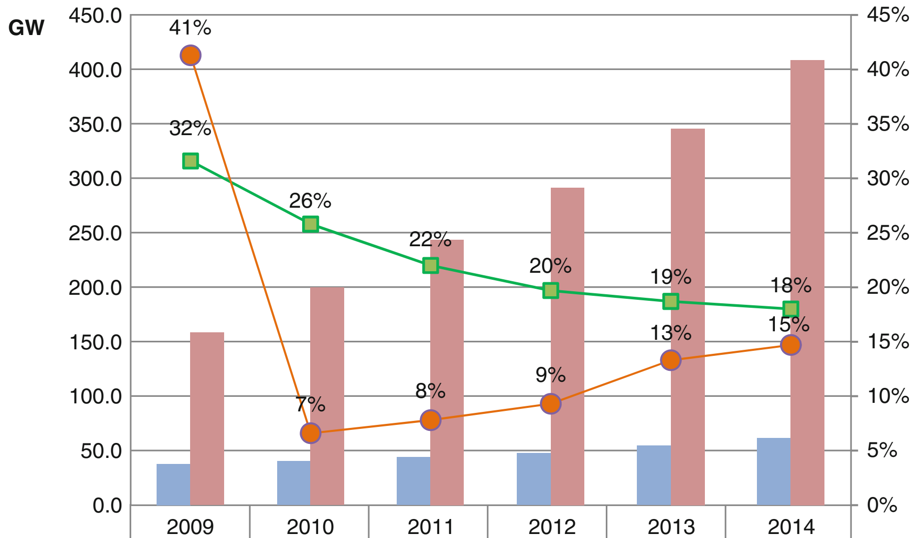
Global Wind Power Installations. Figure 4
Annual market forecast by region 2009–2014 (2009 edition of [9])

economic benefits, reflected in the economy, wind energy technology also adds value by reducing carbon emission, diversifying fuel supply and providing stable energy production prices. Source: 2009 edition of [12] and [37].

Market Forecast (Future Directions)

2009 saw a 41% market growth in the wind power industry. This was a surprise to many in the field, who expected growth to be staggered by the financial crisis. In particular, growths in the USA and China have been impressive in the past few years, with China single-handedly accounting for one third of the total annual wind-capacity addition in 2009. Although the growth in the USA is expected to stay somewhat flat in the coming years due to the lack of financing and overall economic downturn, the development in China is set to continue at a breath-taking pace, with well over 20 GW of annual additions. Sustained growth is also expected in India, which will increase its capacity by 2 GW each year. Complimented by growth in other Asian markets, including Japan, Taiwan, South Korea, and the Philippines, the market in Asian is expected to nearly double in the next 5 years, reaching 109 GW of new wind capacity. In Europe, continued growth is also expected, however, not at such a dramatic pace. Regardless, it is expected that a total of 60 GW will be installed by 2014, with large developments in the offshore market. While Germany and Spain are expected to remain the leading European markets, growth in Italy, France, the UK, and Portugal is expected to continue, as well as opening for some new markets in Poland and Turkey (Fig. 3).

The market in Latin America has also been growing stronger than previously thought. Encouraging developments are seen in Brazil, Mexico, and Chile; however, due to the lack of favorable policies for



	2009	2010	2011	2012	2013	2014
Annual installed capacity [GW]	38.3	40.8	44.0	48.1	54.5	62.5
Cumulative [GW]	158.5	199.9	243.9	292.0	346.5	409.0
Cumulative capacity growth rate [%]	32%	26%	22%	20%	19%	18%
Annual installed capacity growth rate [%]	41%	7%	8%	9%	13%	15%

Global Wind Power Installations. Figure 5
Market forecast 2010–2014 (2009 edition of [9])

wind power development in this region, market development will not reach the heights that would be possible to imagine from the amount of excellent wind resources there is. At the end of 2014, a total of 10.7 GW of installation is expected, increasing from the 1.3 GW in 2009.

In the Pacific region, both Australia and New Zealand seem to be firmly on the track for continued growth at a steady pace, with annual additions of 1 GW by 2014, reaching a total installed capacity of up to 6.4 GW by the end of 2014. Both countries have very good wind resources and a great untapped potential, which is slowly being developed.

In Africa and the Middle East, predictions are less certain, and it is expected that the regions will remain small players in the world's wind market. Substantial plans exist for South Africa however, as well as Kenya, Tanzania, Ethiopia, and Egypt are expected to bring the total capacity up to 5.1 GW by 2014.

As can be seen in Fig. 4 below, in total, it is predicted that in 2014, global wind capacity will stand at 409 GW, with an annual market growth rate of 20.9% being sustained throughout the period in terms of total installed capacity (2009 edition of [9] and [3]) (Fig. 5).

Conclusions

Wind energy has the potential to play an important role in the future energy supply in many areas of the world. Within the last 20 years, wind turbine technology has reached a very reliable and sophisticated level. The growing worldwide market will lead to further improvements, such as large wind turbines or new system applications, including offshore wind power plants. These improvements will lead to further cost reductions and over the medium -erm wind energy will not only be able to compete, but be

cheaper than conventional fossil fuel power generation technology. Further research, however, will be required in many areas, for example, regarding the network integration of a high penetration of wind energy.

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Greenhouse Gas Emission Reduction by Waste-to-Energy

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Article Outline

Glossary

Carbon dioxide (CO_2) Is a by-product of the combustion of fossil fuels or organic materials. Carbon dioxide is the principal greenhouse gas (GHG) in earth's atmosphere.

Carbon dioxide equivalents ($CO_{2,eq}$) Greenhouse gases influence the GHG effect in different degrees. Their contribution is calculated in volume (or mole) equivalents to carbon dioxide.

Combined heat and power generation (CHP) Is the simultaneous generation of both electricity and useful heat. Energy at a high temperature level is first converted to electricity and the remaining energy, at a low level, is used to produce heat (e.g., district heating.

Global warming factor (GWF) Expresses the amount of released $CO_{2,eq}$ for a combusted unit of fuel, in Mg $CO_{2,eq}$/Mg of fuel; can be expressed as generated amount of electricity, in Mg $CO_{2,eq}/MWh_{el}$, or heat, in Mg $CO_{2,eq}/MWh_{th}$.

Greenhouse gas (GHG) Gases in the atmosphere that absorb and reemit infrared radiation; they cause the GHG effect that results in heating up of the atmosphere.

Lower heating value(LHV) Also known as net calorific value (CV) of a fuel, defined as the amount of heat released by the combustion of a unit mass of fuel; the LHV assumes that the water produced in combustion is in vapor state and that the latent heat of vaporization is not recovered.

Municipal solid waste (MSW) Predominantly household wastes (domestic wastes) and similar commercial and bulky wastes collected by a municipality. They are in a solid or semisolid form, sludge or liquids are excluded as well as industrial wastes.

Nitrous oxide (N_2O) Also known as laughing gas. Is a major greenhouse gas with a 298 times higher impact factor than carbon dioxide in a 100-year period.

Selective catalytic reduction (SCR) Is the reduction of nitrogen oxides in combustion gases to nitrogen, using a catalyst and anhydrous ammonia, aqueous ammonia, or urea to diatomic nitrogen and water.

Wet weight (ww) Substance in its original state, including combustibles, water, and ash.

Definition of the Subject

Waste management in general plays an important role in the GHG reduction targets of every country. Usually, the generated municipal solid wastes (MSW) are landfilled and in many cases these landfills are not controlled and their emissions are not collected. Collection and treatment of the emissions of regulated landfills can reduce their GHG effect by up to 75%. The reduction of wastes going to landfill and the replacement by a mechanical, biological, and/or thermal treatment lowers the released GHG emissions significantly.

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By means of these processes, the contribution of waste management to the GHG emissions of a nation can be reduced from 3.3% to 1.2% (e.g., in Germany [1]). In addition, the use of waste incineration in a modern waste management system produces electrical power and heat from the wastes. This results in a further decrease of GHG emissions.

Introduction: Importance of Waste Incineration

The principal method of disposing MSW worldwide is landfilling. After the initial wastes are covered by other wastes, atmospheric oxygen cannot reach them and under the prevailing anaerobic conditions, the biogenic carbon in MSW is converted to methane (CH_4) and CO_2. If the landfill is not equipped for landfill gas collection, this CH_4 is emitted into the atmosphere. The global warming potential of CH_4, relative to CO_2 and for a time horizon of 100 years, is between 21 and 25 [2].

In developed nations, more and more landfills are equipped with a landfill gas collection system. The collected biogas is then used to generate electricity or heat. This results in reducing GHG emissions, both by reducing the emission of methane and also by the use of fossil fuels substituted by the landfill gas.

Even though modern landfills are secured by ground and surface covers, during operation or if landfill covers are broken after closing the landfill, hazardous substances can be emitted in the environment. The major task of waste incineration plants recovering energy (waste to energy – WtE or energy from waste – EfW) is the environmentally friendly disposal of waste and the destruction of hazardous substances during the combustion process. Modern air pollution control systems clean the flue gas to emission levels below the EU standards. However, the production of the greenhouse gas (GHG) CO_2, resulting from the oxidation of carbon in the MSW, is unavoidable. Also, a small amount of another greenhouse gas, nitrous oxides, is emitted; although this amount is small, as compared to the CO_2 emissions, it has to be assessed, because NO_x has a lifetime of 114 years in the atmosphere and its global warming potential is 298, in a time horizon of 100 years [2].

The thermal energy in the WTE flue gases is transferred to water and steam in a boiler and is used to generate electricity in a steam turbine or for district heating. Overall, the combined effect of WTE, that is, reducing landfill emissions and generating electricity, results in a GHG reduction of 1 t of CO_2 per ton of MSW combusted, for landfills that do not capture landfill gas, or half a ton of CO_2 for those that do (www.wte.org).

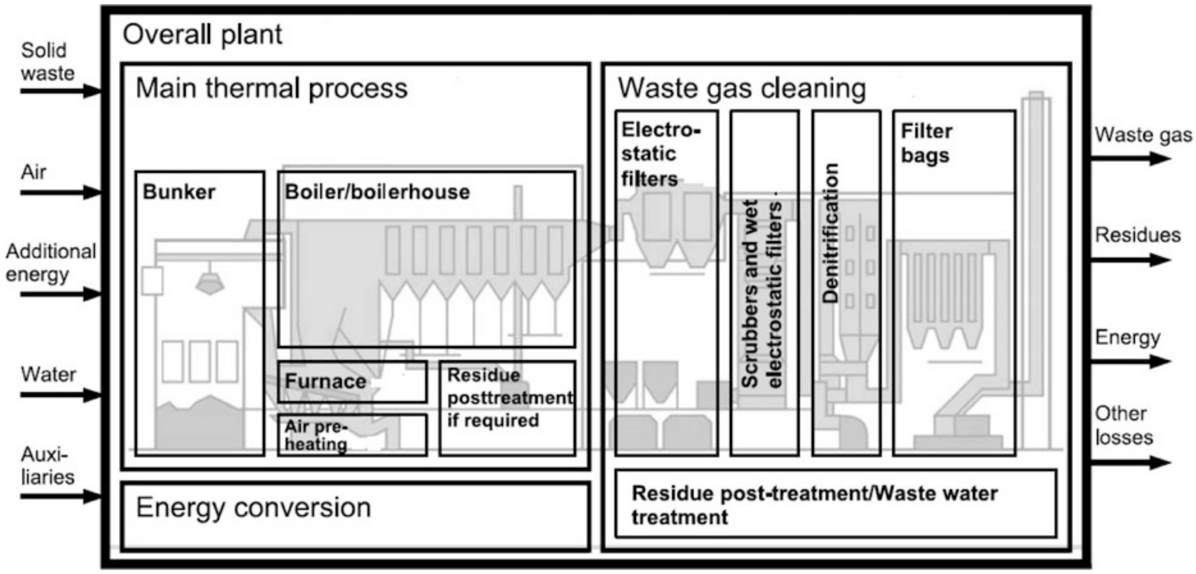
Release of Greenhouse Gas Emissions by Waste Incineration

A modern waste incineration plant consists of the combustion chamber where the waste is converted into ash and hot flue gas. The wastes are used as fuel, and an airflow provides the oxygen needed for combustion. The thermal energy of the combustion gases is transferred to steam in the boiler and superheater tubes, and the steam is used to generate electricity and also process steam and district heating. The cooled flue gas is treated in a flue gas purification system, and the clean gas is emitted to the atmosphere – necessary oxygen. A fossil fuel, for example, natural gas or fuel oil, is used only for start-up and shutdown operations. Water is used in the water steam cycle and, in some cases, in the flue gas purification system. The cleaned gas consists of nitrogen, CO_2, water, and oxygen. The residues include the incineration ash and the flue gas purification residues. Figure 1 shows the incoming and outgoing material and energy flows in a waste incineration plant.

For the calculation of GHG emissions, the waste fuels and any use of auxiliary energy are taken into account. Air, water, and auxiliaries do not produce significant GHG emissions. The clean gas containing the GHG and the delivered energy amounts, substituting energy produced and therefore their avoided GHG, need to be considered.

Determination Methods for Determining the Fossil-Based and Biogenic Carbon Content of MSW

In order to estimate the carbon footprint of waste incineration, it is necessary to know the fossil-based carbon content of MSW. The carbon contained in the biogenic fraction of MSW and the corresponding CO_2 emissions are, by definition [4], classified as carbon neutral. The determination of the biogenic and fossil parts of the carbon can be made by means of a direct procedure (determination by the composition of the



Greenhouse Gas Emission Reduction by Waste-to-Energy. Figure 1
Material and energy flows in a typical waste incineration plant [3]

waste mixture) or an indirect one (determination in the flue gas) as discussed below.

In *manual sorting*, the waste mixture is separated to different waste fractions, and the biogenic and fossil parts in these single fractions are determined.

Selective extraction is a wet chemical procedure where oxidation of biogenic to non-biogenic components is used to identify the biogenic part of the waste mixture.

The ^{14}C *or radio carbon method* is based on the difference in the age of fossil and biogenic materials. Because of the decay of the radioactive carbon isotope ^{14}C, its concentration decreases with time. Because of its age, fossil carbon contains no ^{14}C, whereas biogenic carbon contains a relatively higher ratio of $^{14}C/^{12}C$. Therefore, the biogenic part in the CO_2 of the WTE stack gas is proportional to the ^{14}C content, which can be measured by an instrumental method.

The *balance method* combines a theoretical mass balance with measurable operating data of an incineration plant. Every balance equation is characterized by a specific feature of the waste, for example, ash content, carbon content, etc., and the waste input is theoretically divided into four groups: inert, biogenic, fossil, and water. By solving these mass balance equations and with the help of nonlinear correction calculations, the biogenic carbon content can be determined.

The literature shows that their results are in the same range [5]. The manual sorting method is used in this section. The carbon isotope techniques are discussed in another section of the Encyclopedia.

Waste Composition

The basis of all calculations regarding released GHG emissions of wastes by the manual sorting method is the waste composition. First of all, the aggregate waste has to be separated in their different waste fractions. This is usually done manually. The composition is dependent on the kind of waste (municipal solid waste, commercial waste, industrial waste, etc.) and, especially for the municipal solid waste (MSW), on the following:

- Country, region
- Climate
- Settlement structure
- Season
- Economic situation
- Waste collection system

In different countries, rules and laws are existing influencing the waste management and finally the

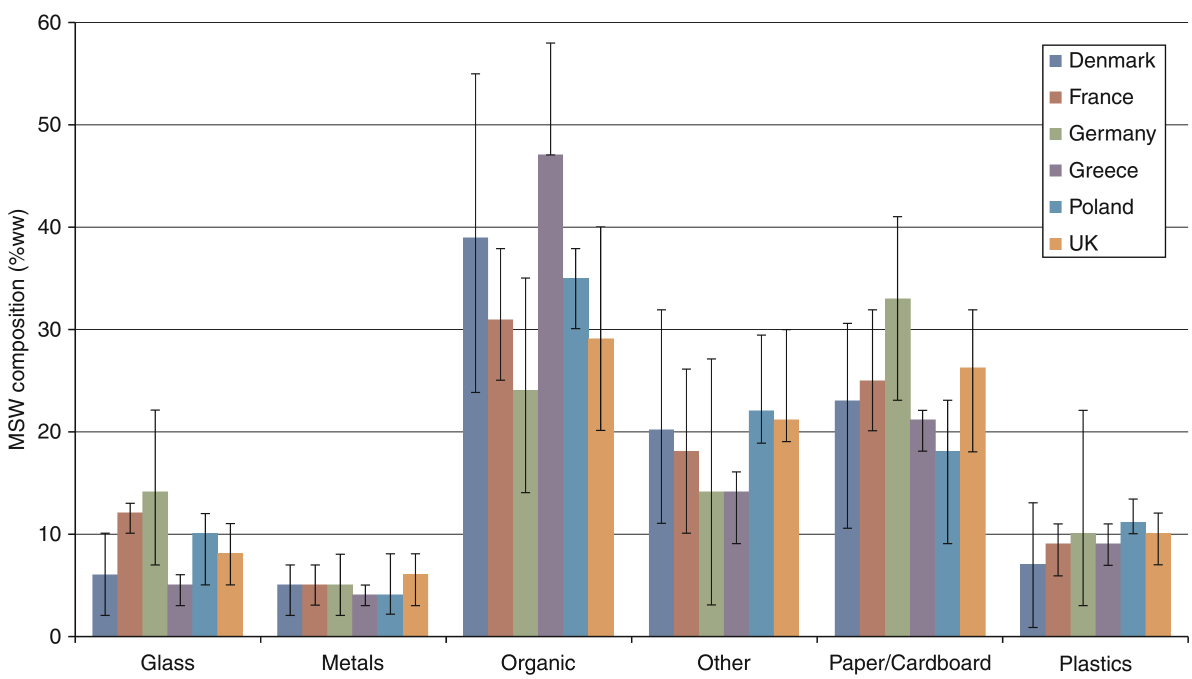
waste composition. As an example, in countries requiring a deposit on several materials like glass, plastic bottles, or cans, people source-separate these materials to get their money back. As a result, only a small part of such materials end up in the MSW. Also, when special bins for organic wastes, glass and paper are provided in a region or country, the amount of these materials in the MSW are reduced appreciably. In regions with hot and dry climate, the generated MSW contains a smaller fraction of organics than in wet climate areas. The reason is that fruits and vegetables grow well in these wet areas and after consumption the residues end up in the MSW.

Organics are often composted, and the compost is used in the gardens of rural areas; thus, this fraction is very small in the MSW. In urban areas, where there is no possibility of composting, the organics remain in the MSW. Another example is the higher amount of minerals and ash in the MSW of communities where coal or wood is used for heating. Also, during the winter season the amount of organic garden waste decreases while in the summer and autumn this fraction increases significantly. Ash residues also disappear in the summer months.

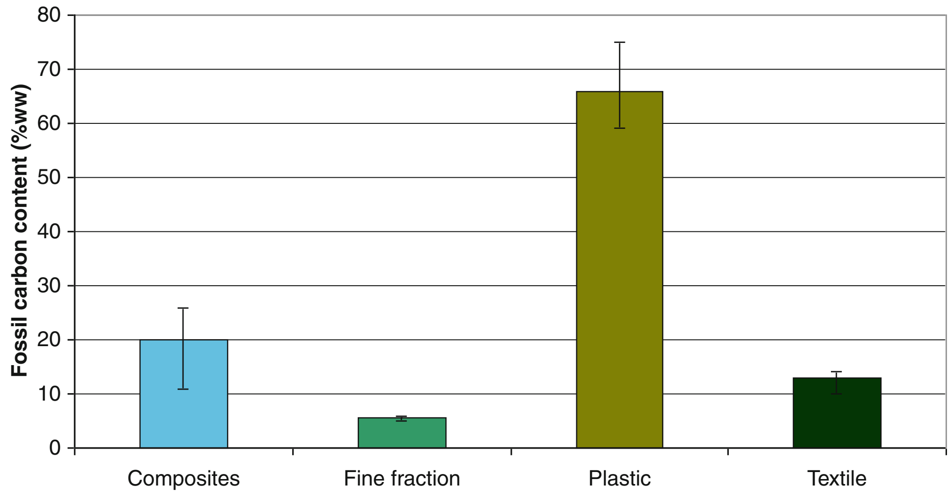
Economic development also results in greater consumption and generation of wastes, such as plastics, cardboard, and other packaging materials. Modern waste collection systems with single collection of glass, paper, cardboard, and plastics, as well as the possibility of sending back the used products to the manufacturers also reduce the amount of MSW and also influence their composition.

MSW is very heterogenic in nature, and no standard methodology exists for defining the waste composition [6]. It is therefore difficult to compare compositions resulting from different types of sorting analysis. Information about MSW composition in different EU countries was compiled by Gentil [7] and is shown in Fig. 2.

As illustrated in Fig. 2, the organic and paper/cardboard fractions constitute about 50% of the wet MSW, as received. Glass and plastics amount to about 10% each, and metals about 5%. "Other" materials (minerals, pollutants, composite materials, textiles, and fines) range from 15% to 20%. The error bars show the



Greenhouse Gas Emission Reduction by Waste-to-Energy. Figure 2
MSW composition in various European nations (Gentil, [7])



Greenhouse Gas Emission Reduction by Waste-to-Energy. Figure 3
Fossil carbon content of different materials contained in MSW

minimal and maximum values observed in a particular nation due to seasonal and other conditions.

Fossil Carbon Content of MSW

The total amount of carbon (TC) in MSW is estimated on the basis of the CO_2 released in combustion tests. The biogenic and fossil carbon parts can be estimated from the overall composition of the MSW or by carbon-14/carbon-12 measurements of the WTE stack gas, as described in another section of this Encyclopedia. The only materials containing fossil carbon are composite materials, plastics, and some textiles. Figure 3 shows the measured fraction of fossil carbon in various materials contained in MSW, as reported in the literature [7–13].

Due to the polymeric structure and the low water content of plastic, the concentration of fossil carbon is very high (65–75%). The composite, textile, and fine fractions contain both biogenic and fossil-fixed carbon, and therefore their fossil carbon content is relatively low.

Global Warming Factors of Different Waste Types in Germany

The MSW collected by a municipality consists mostly of household wastes, but also includes bulky wastes, commercial waste that is similar to household wastes. In many communities, there is source-separation and collection of recyclables that are transported to materials recovery facilities (MRF) where they are separated either mechanically or manually to different recyclable streams. Between 2005 and 2007, the Institute of Waste Management and Contaminated Site Treatment of the Technical University of Dresden and the Intecus GmbH carried out an intensive campaign to analyze the waste types of household waste, similar commercial waste, and bulky waste all over Germany. The results of this investigation are shown in Table 1 [10].

Compared to the data that were shown in Fig. 2, Table 1 includes more waste fractions but the values are in the same range. The advantage of more detailed analysis is in providing a more accurate picture of the fractions of fossil and biogenic carbon. The estimated empirical values of materials of fossil origin are used to provide the estimated fossil carbon content of household, bulky waste, and commercial wastes (Table 2).

As shown in Table 2, textiles in household waste consist mostly of biogenic materials like cotton, and the fossil mass fraction is only 35%. Bulky waste contains a lot of carpets made of synthetic materials, and the fossil carbon fraction is 80%. Table 3 shows the calculated total carbon content of various materials.

There are no significant differences among the total carbon contents of the different waste materials. Thus,

Greenhouse Gas Emission Reduction by Waste-to-Energy. Table 1 Composition of different waste types [10]

Waste fraction	Household waste (% ww)	Bulky waste (% ww)	Commercial similar household waste (% ww) (M.-%)
Organic	30.9	0.6	13.2
Wood	1.9	42.6	6.3
Textiles	4.9	5.3	3.0
Minerals	4.6	1.7	4.8
Composite materials	4.7	26.3	8.6
Hazardous materials	0.6	0.1	0
Others	10.6	11.0	7.3
Fine fraction <10 mm	14.7	0.2	17.5
Fe/NE metals	2.7	5.0	3.0
Paper/ cardboard	10.5	2.4	17.1
Glass	4.9	0.1	4.4
Plastic	9.2	4.7	14.8

Greenhouse Gas Emission Reduction by Waste-to-Energy. Table 2 Estimated fossil carbon fraction of materials contained in three types of waste [10]

Waste fraction	Household waste (% ww)	Bulky waste (% ww)	Commercial similar household waste (% ww) (M.-%)
Textiles	35	80	70
Composite materials	70	60	40
Others	20	90	50
Fine fraction <10 mm	40	40	20
Plastic	100	100	100

Greenhouse Gas Emission Reduction by Waste-to-Energy. Table 3 Total carbon content of waste fractions with fossil portions [10]

Waste fraction	Total carbon content (Mg C/Mg of waste material)
Textiles	0.37
Composite materials	0.38
Others	0.19
Fine fraction <10 mm	0.14
Plastic	0.62

the same total carbon content is assumed for all waste types, whereas the total carbon contents vary significantly among the waste fractions as shown in Table 3. The calculated fossil carbon contents of various waste materials and three different types of wastes (household, bulky, and commercial) are shown in Table 4.

The fossil carbon content is 62%; therefore, plastics bring most of the fossil carbon into the MSW. The fossil carbon contents of all other waste fractions are considerably lower and they range from 3% to 36%.

The estimated content of fossil carbon in the waste fraction multiplied by the corresponding wet weighted amount in the waste composition (see Table 1) yields the content of fossil carbon in each waste material of the three types of wastes (Table 5).

Table 5 shows that, in total, 8.8% of the wet household waste consists of fossil carbon, 12.1% of the bulky waste, and 12.4% of the commercial waste that is similar to household waste.

During combustion, the carbon is oxidized to CO_2 and emitted to the atmosphere. A small amount of carbon may not be oxidized and leaves in the incinerator ash. In the literature, the oxidation of carbon, that is, the efficiency of combustion, is reported to be in the range of 95% and 100% [10, 12, 14]. In the following calculations, an oxidation of 97% was assumed for all waste types. Also, the conversion factor from carbon to CO_2, that is, 44/12 on the basis of the respective molecular weights, must be taken into account. On the basis of these data, the CO_2 emission factors for the three

Greenhouse Gas Emission Reduction by Waste-to-Energy. Table 4 Fossil carbon content per ton of waste, for different waste materials and type of wastes

Waste fraction	Household waste, Mg C_{fossil}/ Mg waste	Bulky waste, Mg C_{fossil}/ Mg waste	Commercial similar to household waste Mg C_{fossil}/ Mg waste
Textiles	0.13	0.30	0.26
Composite materials	0.26	0.22	0.15
Others	0.36	0.17	0.09
Fine fraction <10 mm	0.06	0.06	0.03
Plastic	0.62	0.62	0.62

Greenhouse Gas Emission Reduction by Waste-to-Energy. Table 5 Fossil carbon content per ton of *waste type*, for different waste materials and type of wastes

Waste fraction	Household waste, Mg C_{fossil}/ Mg waste type	Bulky waste, Mg C_{fossil}/ Mg waste type	Commercial similar household waste, Mg C_{fossil}/ Mg waste type
Textiles	0.0063	0.0157	0.0077
Composite materials	0.0121	0.0570	0.0130
Others	0.0038	0.0188	0.0069
Fine fraction <10 mm	0.0082	0.0001	0.0049
Plastic	0.0571	0.0291	0.0917
Total	0.0876	0.1207	0.1244

types of waste included in MSW are calculated to be as follows:

- Household waste: 0.312 Mg CO_2/Mg waste
- Bulky waste: 0.429 Mg CO_2/Mg waste
- Commercial waste similar to households: 0.443 Mg CO_2/Mg waste

As noted earlier, in addition to CO_2, the other important GHG gas emitted by WTE plants is nitrous oxide (N_2O). N_2O has a long residence time in the atmosphere of 114 years because there appears to be no natural removal processes for this gas [15]. Other GHG trace gases, such as carbon monoxide (CO) that has a global warming potential of 1.9 for a time horizon of 100 years, are not considered because their contribution to GHG is negligible.

The estimated total GHG emissions for the three types of wastes collected in the MSW stream are shown below:

- Household waste: 0.315 Mg $CO_{2,eq}$/Mg ww
- Bulky waste: 0.432 Mg $CO_{2,eq}$/Mg ww
- Commercial waste similar to households: 0.446 Mg $CO_{2,eq}$/Mg ww

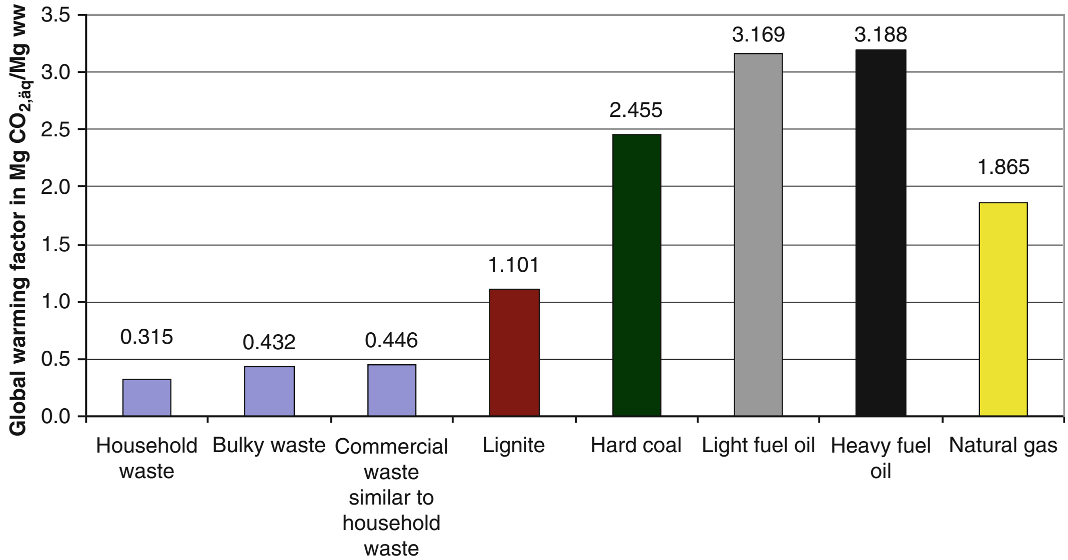
As discussed earlier, the identified global warming factors (GWF) depend on the waste composition and their biogenic and fossil carbon contents. The GWF can vary considerably from area to area. For household waste in industrial countries, the GWF ranges between 0.253 Mg $CO_{2,eq}$/Mg waste [16] to 0.557 Mg $CO_{2,eq}$/Mg waste [17].

Comparison of Global Warming Factors of MSW with Fossil Fuels

The carbon content of fossil fuels is by definition of fossil origin. Figure 4 compares the calculated global warming factors of three types of wastes in the MSW stream with those of fossil fuels listed in the Global Emission Model for Integrated Systems (GEMIS) [18].

Figure 4 shows that, with the exception of lignite, the global warming factors of MSW are one order of magnitude lower than the various types of fossil fuels used to generate electricity and heat. However, it is also necessary to consider the amount of energy that is generated by the various fuels. Table 6 shows the respective lower heating value (LHV) of the fuels.

The three waste types have a LHV ranging from 2.5 to 3.4 MWh/Mg of waste. The better fossil fuels range in LHV from 7 to 11.8 MWh/Mg of fuel, which is two to three times higher than MSW. The only exception is lignite which, because of its high water content,



Greenhouse Gas Emission Reduction by Waste-to-Energy. Figure 4
Calculated global warming factors of different waste types and of fossil fuels (per Mg of wet fuel)

Greenhouse Gas Emission Reduction by Waste-to-Energy. Table 6 Estimated LHV of selected fuels [10, 18] and own calculations

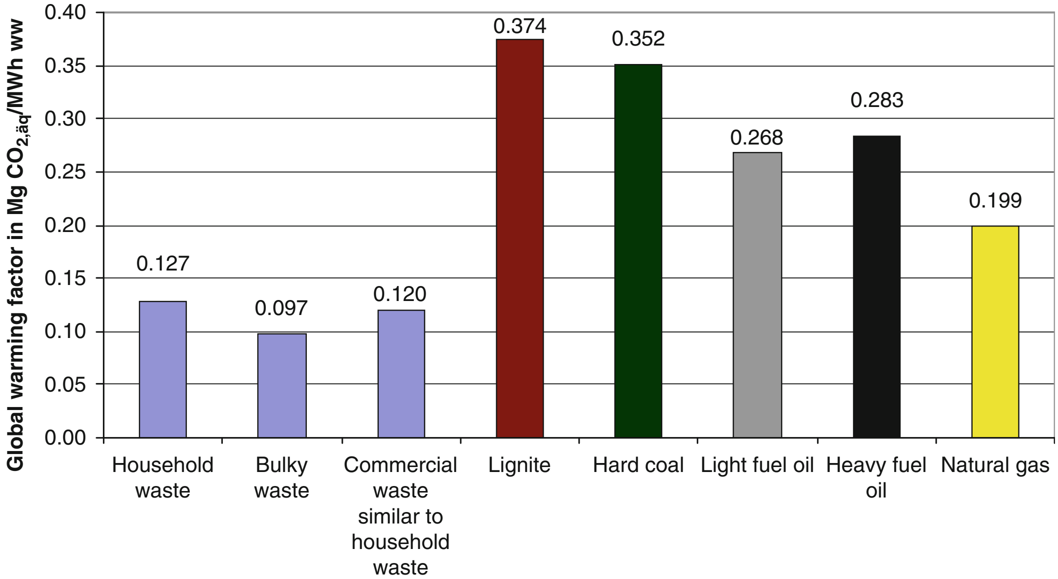
Fuel	LHV in MWh/Mg wet weight (MWh/Nm^3 for natural gas)
Household waste	2.468
Bulky waste	4.441
Commercial similar household waste	3.701
Lignite	2.941
Hard coal	6.980
Light fuel oil	11.836
Heavy fuel oil	11.275
Natural gas	9.392

is in the same range as MSW. The LHV of natural gas is shown in MWh/Nm^3 because at standard conditions (293 K and 101 kPa) it is in the gaseous form. The relation of the global warming factors and the corresponding LHV of the various fuels as used is shown in Fig. 5.

Figure 5 shows that the GWF of MSW, per MWh of contained thermal energy, is only one third to one half that of fossil fuels. The main reason is that the biogenic carbon content of MSW has been assigned zero global warming factor, $CO_{2,eq}$/MWh.

The consequence is that when wastes are incinerated with the same energy efficiency like fossil fuels, the corresponding GHG emissions for the same amount of energy delivered is two to three times lower than for fossil fuels. Or, in other words, the released GHG emission for a delivered amount of energy, from waste or from natural gas, would be the same even if the efficiency of energy recovery of waste incineration were to be one half that of natural gas combustion.

The weighted average *gross* heat efficiency of German WTE plants in 2007 was estimated to be 36.5% [10] and the average weighted *net* heat efficiency was 27.8% [19]. For the 231 European plants that generate both electricity and district heating, an average weighted *gross* heat efficiency of 46% was calculated [20] but the net efficiency was not provided; on the basis of operating experience of WTE plants, it is expected that the average net heat efficiency of these plants is about 35%. The electrical efficiency does not differ significantly between countries because the technology for power generation is everywhere available,



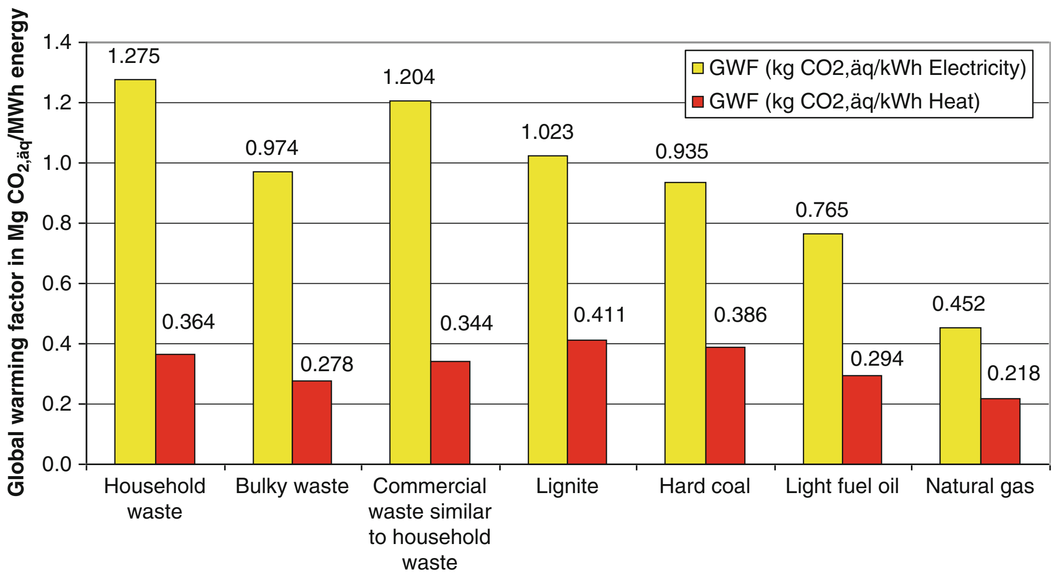
Greenhouse Gas Emission Reduction by Waste-to-Energy. Figure 5
Global warming factors of various types of wastes and fuels expressed as Mg CO_2/MWh of thermal energy

and even in developed countries like Germany old incinerators continue to operate.

In the case of heat generation efficiency, a difference between southwest and northern Europe is visible. The gross heat efficiency in southwestern Europe is around 22% and in northern Europe around 83% [21]. The principal reason is the extensive use of WTE plants for district heating in the north. Heat has to be used close to the place of production because the transfer over higher distances is not economic. If there is no district heating network or industrial plant requiring heat, the low-level thermal energy exiting the turbine is wasted by air or water condensation. Because of their high emissions, decades ago, many incinerators were built far away from settlement structures. Consequently, even in Germany where energy efficiency is an important part in the GHG reduction targets of the government, the heat efficiency of the WTE plants is rather poor.

Another important fact is the climate. In southwestern Europe heat is simply not needed because of relatively high temperatures all year round. A conversion from heat by absorption refrigeration to cooling is technically possible, but special cooling networks and cooling energy costumers are necessary. The opposite is in northern Europe. Cold climate and high heat requirements combined with an intelligent energy provision and generation system makes high efficiencies possible. In northern European countries, such as Denmark, WTE plants are positioned close to district heating networks and there is intelligent integration of the WTE plants in the heating system of an area. The simultaneous production of electrical power and heat in a single process of a power plant is called combined heat and power generation (CHP) and ensures maximum efficiency in recovering energy. The very efficient incineration plants in northern Europe are using this technology.

Even when the combined heat and power generation is very efficient is financially supported, as for example in the case of CHP in Germany, most of the large fossil fuel power plants produce exclusively electricity. The electrical net efficiency of lignite power plants is around 36.6%, of hard coal power plants 37.6%, of light and heavy fuel oil around 35%, and of natural gas 43.9% [22]. Usually the produced heat of these power plants is not used, and in the case of lignite, hard coal and natural gas power plants that seek to have a high electrical efficiency, the steam is condensed to



Greenhouse Gas Emission Reduction by Waste-to-Energy. Figure 6
Calculated global warming factors of different waste types and fossil fuels referring a unit of delivered energy

relatively low temperatures. This low-level energy cannot be used for district heating.

In comparison, smaller heating plants that are designed to produce only heat have a net heating efficiency of around 91%, using the same fossil fuels [23]. Because of high emissions, heavy fuel oil is not used anymore for power generation in most industrial countries. However, it is still used for fuelling ships and tankers.

Figure 6 shows the global warming factors per unit of energy content, as illustrated in Fig. 5, divided by the corresponding net efficiencies of the power plants using these fuels. The result of this division yields the amount of released GHG per unit of delivered electrical power or heat.

The low electrical net efficiency of 10% and the heat net efficiency of 35% from WtE plants cause the GWF of around 1 Mg $CO_{2,eq}$/MWh of electricity and about 0.3 Mg $CO_{2,eq}$/MWh of heat from wastes (Fig. 6). The higher net efficiencies of fossil-fired power plants of about 40% for electricity and 90% for heat result in GWF ranging from 0.45 to 1 Mg $CO_{2,eq}$/MWh of electricity and from 0.2 to 0.4 Mg $CO_{2,eq}$/MWh of heat for the most efficient power plants (Fig. 6).

However, it should be noted that the global warming factors for the most efficient WTE facilities are obtained by cogeneration of power and heat. The net efficiencies of 40% for power and 90% for heat for fossil-fired power plants are not possible in the case of cogeneration of electricity and heat.

Reduction of GHG Emissions and Conservation of Fossil Fuels by Means of Energy Recovery from Wastes

The energy released by the combustion in the waste incineration plants is used to produce electricity and/or heat. The effect of this is to decrease the consumption of fossil fuels, thus conserving a nonrenewable resource. The effect of this contribution to the overall mix of power generations differs from country to country. The amount of nuclear energy and renewable energy used, the amount of fossil fuels used, and the degree of cogeneration play an important role. Also, the efficiency of electricity generation from fossil fuels has a big influence on the electricity mix factor. In turn, the electricity mix factor results in the overall GWF (Mg $CO_{2,äq}$/MWh) of a nation. This factor is also affected by the upstream and downstream emissions associated with the mining, processing, and transport of the fuels; the construction and demolition of the energy-producing facilities; and the disposal of by-products, such as coal ash and nuclear wastes.

The electricity mix factors of many countries are calculated every year and are available in the literature. In the EU, the electrical mix factor ranges from 0.007 Mg $CO_{2,äq}/MWh_{el}$ for Norway, which uses renewable hydropower, to 1.13 Mg $CO_{2,äq}/MWh_{el}$ for Poland, which depends on lignite-fired power plants [24]. Developed industrial economies with a wide mix of nuclear, coal, and renewable energy have GWF of about 0.6 Mg $CO_{2,äq}/MWh_{el}$ [24, 25].

The heat mix factors are more difficult to calculate. The big difference between electricity and heat is in the ways that these two kinds of energies are produced and supplied to the users. Electricity is usually produced in a relatively small number of large power plants and is distributed by means of national grids. Heat is generated by a multitude of generating sources, including residential boilers, industrial and municipal boilers, and many other sources. Heat can be produced in cogenerating plants, as a by-product of industrial processes, and also by geothermal or solar energy and is delivered either as steam or warm water. It is therefore much more difficult to compile statistics on the GWF of heat generation than in the case of electricity. For the current 27 countries of the European Union, a weighted heat mix factor of 0.27–0.32 Mg $CO_{2,äq}/MWh_{th}$ was estimated by Kreissig and Stoffregen [26] and Skovgaard et al. [27]. The German heat mix factor was calculated to be 0.216 Mg $CO_{2,äq}/MWh_{th}$ [22] and for Greece to 0.468 Mg $CO_{2,äq}/MWh_{th}$ [7].

As discussed earlier, the biogenic fraction of MSW energy is over 50%, and the energy delivered by waste incineration plants primarily substitutes energy from fossil fuels. Therefore, it is reasonable to calculate electrical and heat mix factors based on the energy provision of fossil fuels, that is, taking out of the energy mix factor of a country nuclear and renewable energy. The German federal environmental energy prefers to use the fossil energy mix factors for calculating the GHG emission savings resulting from MSW and other biomass combustion. In countries like Poland where nearly 100% of the energy is generated from fossil fuels, the fossil energy mix factors are nearly the same as the actual energy mix factors. In the case of Germany, 30% of electricity is generated by lignite, 60% by hard coal, and 10% by natural gas, when nuclear and renewable energy are excluded from the calculation of the energy mix; in this case, the fossil fuel mix factor is 0.886 Mg $CO_{2,äq}/MWh_{el}$ versus the actual factor of 0.6 Mg $CO_{2,äq}/MWh_{el}$ [22]. The German heat mix factor increases from 0.216 to 0.232 Mg $CO_{2,äq}/MWh_{th}$ [22] when heat is exclusively generated by fossil fuels. When a nation obtains most of its energy from natural gas, the mix factor is about 0.45 Mg $CO_{2,äq}$/MWh for electricity and 0.22 $CO_{2,äq}$/MWh for heat (Fig. 5). When the only fossil fuel is lignite coal, the fossil energy mix factor for electricity is about 1 Mg $CO_{2,äq}$/MWh and for heat 0.4 Mg $CO_{2,äq}$/MWh.

The third scenario is developed to examine the effect of energy provided by WTE as base load operation, that is, on a 24-h basis. Base load plants are primarily nuclear, lignite, and, in some cases, hard coal fired power plants; at times of high demand of electricity, the required peak load power is provided by power plants fired by light oil or natural gas. Waste incineration plants burn waste and provide energy continuously, 24 h a day, and, therefore, are a good base load provider.

In the case of Germany, base load electricity is primarily provided by lignite coal power plants with an electricity factor of 1,088 Mg $CO_{2,äq}/MWh_{el}$ [22]. In Norway or France, where base load electricity is produced by renewable or nuclear energy, the corresponding factor is zero. Because of the difficulties involved in compiling heat generation data, as discussed earlier, it is not possible to calculate the base load heat factor; in this case, the fossil heat mix factor is assumed as the base load factor for generation of heat. The above discussion of GWF is summarized in Table 7.

Greenhouse Gas Emission Reduction by Waste-to-Energy. Table 7 Global warming factors for the generation of electricity and heat, under three substitution scenarios in EU

Substitution scenario	Electrical power [Mg $CO_{2,äq}/MWh_{el}$]	Heat [Mg $CO_{2,äq}/MWh_{th}$]
Actual energy mix	0.007–1.13	0.216–0.468
Fossil energy mix	0.45–1.13	0.22–0.5
Base load	0–1.13	0.216–0.468

As an example, in Germany the use of WTE reduces in the fossil energy mix scenario GHG emissions by the factor 0.886 Mg $CO_{2,äq}$/MWh, of electricity provided by the WTE, and 0.232 Mg $CO_{2,äq}$/MWh, for heat generated by the WTE. For the LHV of household waste presented in Table 6 and the power (10%) and heat (35%) net efficiencies of waste incineration plants, 0.247 MWh of power and 0.864 MWh of heat are provided by the combustion of 1 t (1 Mg) of household wastes. Multiplying these amounts of energy by the emission factors of the fossil energy mix scenario yields the factor of 0.419 Mg $CO_{2,äq}$/Mg of household waste combusted. Comparison with the released GHG emissions from the combustion of household waste of 0.315 Mg $CO_{2,äq}$/Mg (Fig. 4) shows that there is a net reduction of 0.104 Mg $CO_{2,äq}$/Mg of MSW. Figure 7 shows the net prevention of GHG emissions for the three waste types and for the three substitution scenarios.

Figure 7 shows that for Germany, there is a net reduction of GHG emissions, in all three scenarios. The net reduction ranges from 0.02 to 0.14 Mg $CO_{2,äq}$/Mg for household waste to 0.17 to 0.39 Mg $CO_{2,äq}$/Mg for bulky waste. The net reduction is 0.315 for household waste and 0.446 Mg $CO_{2,äq}$/Mg for commercial waste similar to that of households. The difference is due to the higher LHV of the commercial waste.

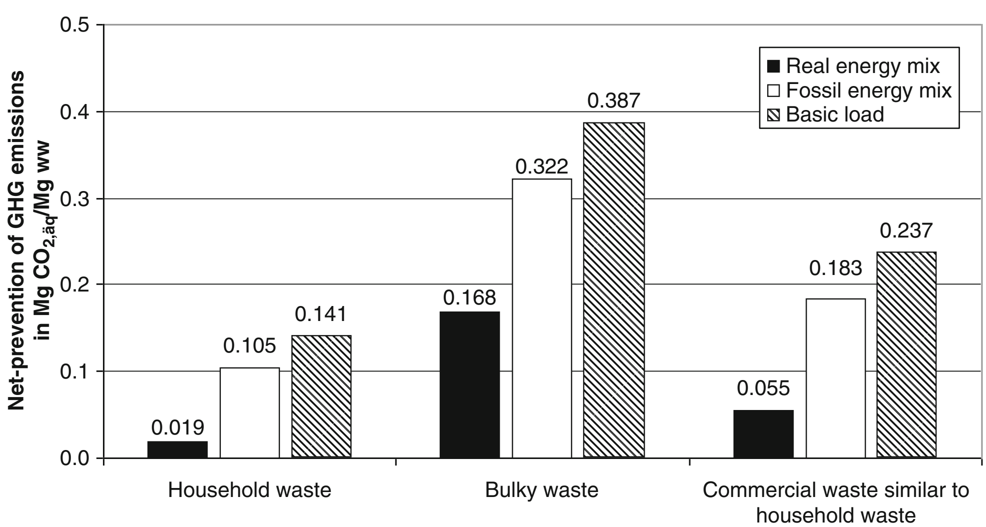
Resource Conservation by Savings of Fossil Fuels

Each unit of energy produced by WTE conserves a unit of fossil fuel energy. Furthermore, every ton of incinerated waste conserves a certain amount of fossil fuels. Using the LHV of Table 6 and the power and heat net efficiencies mentioned earlier, one can calculate the mass of fossil fuels conserved per ton of MSW combusted (Fig. 8).

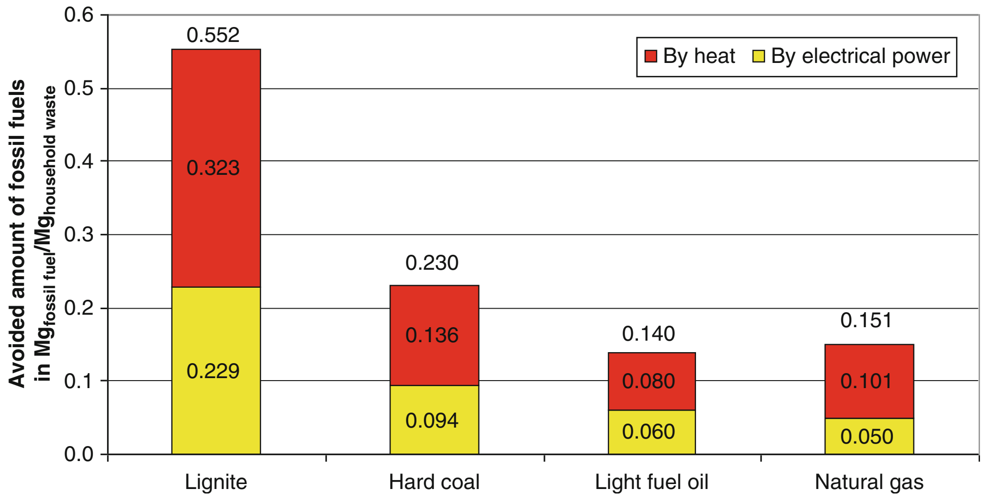
In an average WTE plant, between 0.15 Mg of natural gas and 0.55 Mg of lignite can be avoided by the incineration and energy recovery of 1 Mg of household waste (Fig. 8). In the case of heat generation, the amount of avoided fossil fuel per ton of MSW is higher because the energy efficiency of heat-generating WTE is higher than that for electricity. The higher is the LHV of the MSW combusted, the higher will be the reduction in GHG emissions. For example in the case of bulky waste (Table 6), 1 t of waste decreases the use of lignite by about 1 t.

Greenhouse Gas Emissions by Landfilling

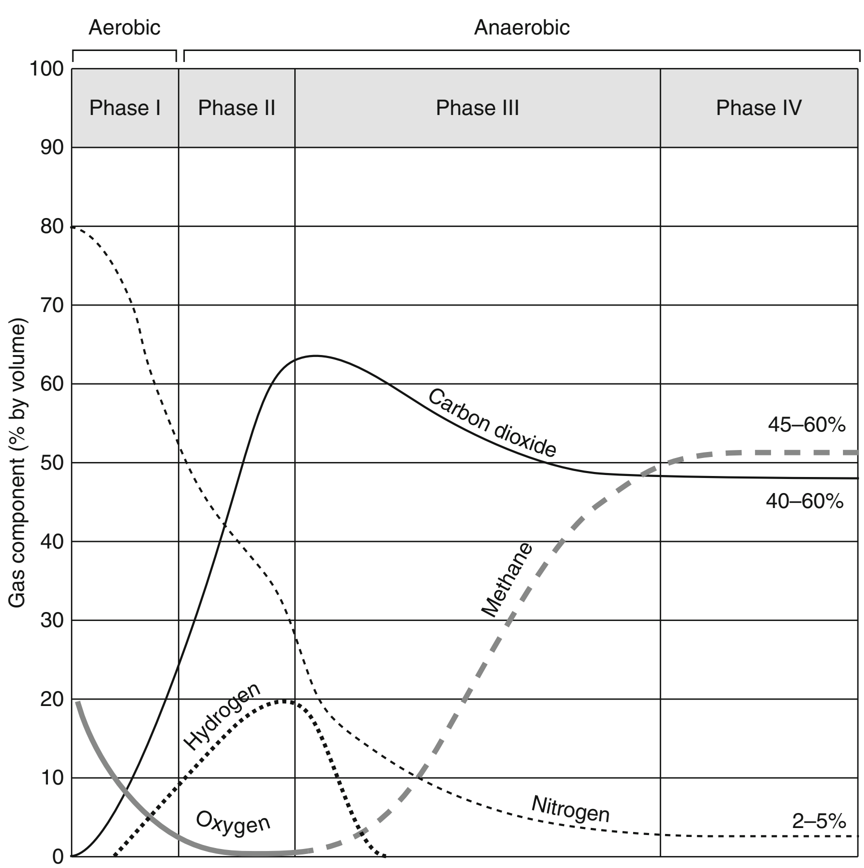
As noted earlier, landfilling continues to be the dominant method of disposing MSW worldwide. Under the prevailing anaerobic conditions in a landfill and in the presence of water, the biogenic components of MSW are converted to methane and carbon dioxide. Figure 9



Greenhouse Gas Emission Reduction by Waste-to-Energy. Figure 7
Net reduction of GHG emissions in Germany for the three substitution scenarios and three types of waste



Greenhouse Gas Emission Reduction by Waste-to-Energy. Figure 8
Conserved amount of various fossil fuels by the combustion of 1 t (1 Mg) of MSW in WTE



Greenhouse Gas Emission Reduction by Waste-to-Energy. Figure 9
Changes in landfill gas composition with time [28]

illustrates that in Phase I, when wastes are first dumped, air can flow through the wastes; under these conditions, aerobic bacteria consume oxygen and break down the long molecular chains of complex proteins, lipids, and carbohydrates. The oxygen concentration decreases, and the concentration of produced carbon dioxide increases. Phase I lasts for days to several months, depending on how loose or compressed the waste is. In Phase II, oxygen is depleted, and carbon dioxide reaches the concentration of over 60%. When anaerobic conditions are reached, methanogenic bacteria produce methane and carbon dioxide and, at the beginning of Phase IV, the generated landfill gas consists of nearly equal volumes of methane and carbon dioxide. It may take a few years until the stable Phase IV is reached, depending on waste composition, moisture content, temperature within the landfill, and other factors. Phase IV can last several decades with a stable landfill gas composition.

If there is no infiltration of rainwater in the landfill, the production of landfill gas decreases.

Modern, controlled landfills, also called sanitary landfills, are provided with ground sealing and also landfill gas collection systems. However, it may take several years for the landfills to be covered and the gas collection system to start operating. During this time, rainwater can flow through the wastes, and methane gas is formed. The amount of resulting GHG emissions from landfills is primarily dependent on the biogenic carbon and the water content in the wastes. The degradation of the biogenic carbon depends more on the water to solids ratio than on the age of the landfill. In order to calculate the production of landfill gas, one needs to know the amount of biogenic carbon in the different wastes types. The amounts shown below are based on the calculation of the fossil carbon (see section on "Global Warming Factors of different Waste Types in Germany"):

- Household waste: 0.122 Mg C_{bio}/Mg waste
- Bulky waste: 0.232 Mg C_{bio}/Mg waste
- Commercial waste similar to household waste: 0.097 Mg C_{bio}/Mg waste

In practice, the amount of produced landfill gas is calculated by means of mathematical models that describe the decomposition and gas generation processes using mathematically formulated procedures in combination with empirical factors. A commonly used model in Europe was developed by Tabasaran and Rettenberger on the basis of the following formula [29]:

$$G_t = 1.868 \cdot C_{bio} \cdot (0.014 \cdot T + 0.28) \cdot \left(1 - 10^{-kt}\right)$$

where

G_t = produced amount of landfill gas [m^3/Mg ww]
C_{bio} = biodegradable carbon [Mg C/Mg ww]
T = temperature [°C]
k = degradation constant [a^{-1}]
t = time since deposition [a]

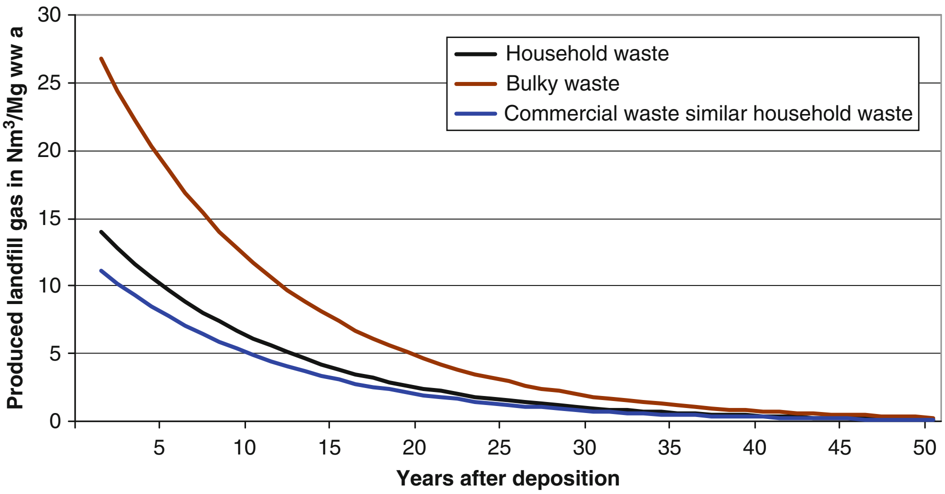
The factor 1.868 indicates the amount of landfill gas (in liters) stoichiometrically produced by 1 g of biogenic carbon. The temperature T in landfills is in the mesophilic range and is assumed to be 30°C. The degradation constant is calculated from the formula by ln $2/T_{1/2}$, where the average half-life $(T_{1/2})$ used by the authors is 18 years, and k is calculated to be 0.04. Easily biodegradable material like food wastes have a shorter half-lives than paper and wood that contain lignin; however, to simplify the calculation, the half-life of 18 years is assumed for all waste types. The amount of landfill gas produced annually, using the formula of Tabasaran and Rettenberger, is shown in Fig. 10.

According to Fig. 10, landfill gas production would be nearly finished after 50 years. The accumulated amount of landfill gas over the 50-year period is 158 Nm^3 per Mg of wet weight of household waste, 301 Nm^3 per Mg for bulky waste and 126 Nm^3 per Mg of commercial waste similar to households.

For an assumed distribution of 50% methane by volume and 50% carbon dioxide, the molar mass of methane (16 g/mol) and carbon dioxide (44 g/mol), the molar volume of gases at standard temperature and pressure (22.4 L/mol), and an assumed GWF for methane of 23, the following amounts of GHG emissions are released per ton of waste:

- Household waste: 1.449 Mg $CO_{2,äq}$/Mg waste
- Bulky waste: 2.766 Mg $CO_{2,äq}$/Mg
- Commercial waste similar to household waste: 1.155 Mg $CO_{2,äq}$/Mg

These amounts will be emitted to the atmosphere in landfills that are not provided with gas



Greenhouse Gas Emission Reduction by Waste-to-Energy. Figure 10
Calculated amount of landfill gas generated annually

collection systems. In controlled (sanitary) landfills, over 50% of the total biogas generated can be captured and the rest is emitted to the atmosphere. The following section shows that the amount of GHG emissions from landfills is considerably higher than the GWF associated with the combustion of MSW in WTE.

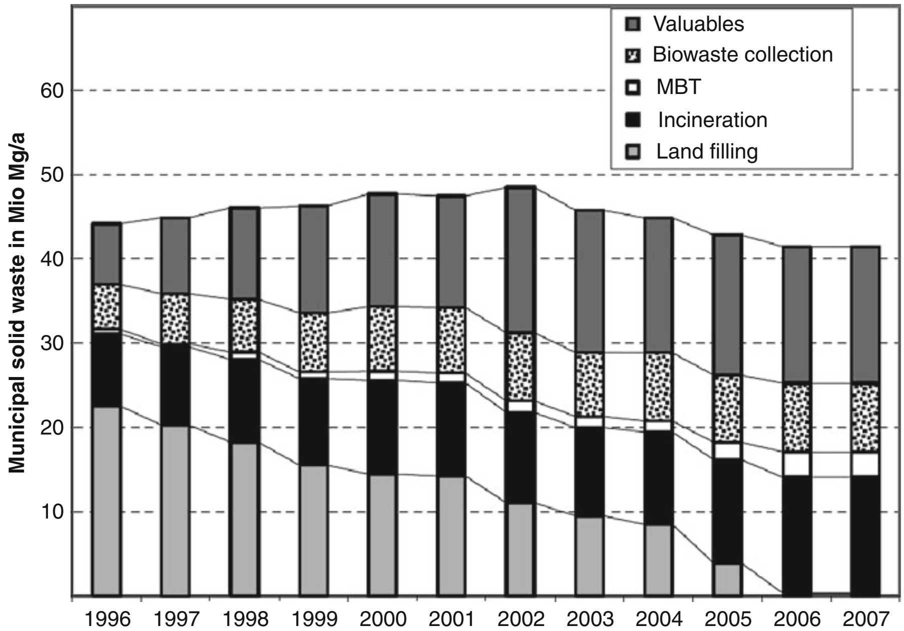
The Germany Example

Since 2005, landfilling of untreated MSW in Germany is prohibited; the primary reason is to reduce the landfill gas potential of the disposed waste. At this time, the post-recycling MSW goes directly to waste incineration or to mechanical and biological treatment (MBT) plants; in 2007, there was no landfilling of untreated MSW. In the MBT plants, some recyclables are recovered, green and food wastes are stabilized, and a high calorific value material is produced that may be used as a solid fuel (SRF or RDF). Figure 11 shows the disposition of municipal solid wastes in Germany, in the years 1996–2007 [30]. It can be seen that only a small fraction goes to BMT, 50% of the post-recycling MCW is combusted in WTE facilities, and in the period 1997–2007 landfilling was reduced from about 23 million tons to zero.

Greenhouse Gas Emissions by Waste Incineration in Germany 2007

In the year 2007, about 17.8 million tons of MSW were incinerated in 66 German waste incineration plants. The waste input composition was in general about 12.5 million Mg of household wastes, 0.5 million Mg of bulky wastes, and 4.8 million Mg of commercial wastes similar to household waste and other materials [10]. As discussed earlier, (see Fig. 4), the annual GHG emissions from household waste were 3.93, for bulky waste 0.22, and for commercial waste similar to household waste 2.14 million Mg $CO_{2,äq}$.

For the calorific value of the waste mix of about 2.8 MWh/Mg [19], the thermal energy generated by the 17.8 million tons of MSW combusted in 2007 was 49.45 million MWh. In addition, an estimated [19] 1.62 million MWh of external energy was used in the form of light fuel oil used for start-up and shutdown operations or as natural gas used for reheating of the flue gas prior to selective catalytic reduction (SCR); Bilitewski [10] determined that 24% of this auxiliary energy was provided by light fuel oil and 76% by natural gas; as stated earlier (Fig. 4), the GWF of light fuel oil is 0.268 Mg $CO_{2,äq}$/MWh and of natural 0.199 Mg $CO_{2,äq}$/Mg. This use of auxiliary fuels



Greenhouse Gas Emission Reduction by Waste-to-Energy. Figure 11
Disposition of MSW collected in Germany [31]

resulted in the GHG emission of 0.35 million Mg $CO_{2,äq}$. In total, by waste incineration in Germany in the year 2007 emitted about 6.64 million Mg $CO_{2,äq}$.

Reduction of Greenhouse Gas Emissions in Germany by Means of Waste Incineration in 2007

Table 8 shows the amounts of electricity and thermal energy provided by the 66 German waste incineration plants in 2007.

Since the thermal energy input was estimated earlier to be 49.45 million MWh/a minus the 1.62 million MWh of external fuel, the energy efficiency of delivered electrical power was 10.1% and the energy efficiency of delivered heat 26.9%. The combined efficiency of delivered electrical and thermal energy generation was 37%.

In determining the effect of WTE in substituting fossil energy, three scenarios were considered, same as discussed earlier:

- Actual German energy scenario
  - Power mix: nuclear 23%, natural gas 13%, lignite 23%, hard coal 20%, renewables 15%, others 6%; electricity GWF of 0.596 Mg $CO_{2,äq}/MWh_{el}$ [22]
  - Heat mix (39% hard coal, 42% natural gas, 12% lignite, 6% waste); heat GWF of 0.216 Mg $CO_{2,äq}/MWh_{th}$ [32]
- Fossil fuel scenario
  - Power mix: 60% hard coal, 30% lignite, 10% natural gas; electricity GWF of 0.886 Mg $CO_{2,äq}/MWh_{el}$ [22]
  - Heat mix: 57% natural gas, 40.5% light fuel oil, 2.5% coal; heat GWF of 0.232 Mg $CO_{2,äq}/MWh_{el}$ [22, 33]

Greenhouse Gas Emission Reduction by Waste-to-Energy. Table 8 Energy generated by all WTE plants of Germany in 2007 [19]

Type of energy	Amount of energy provided, in million MWh/a
Electrical power	5.16
Heat	13.75
Total	18.91

- Base load scenario
  - Electricity factor based on lignite coal; GWF of 1.088 Mg $CO_{2,äq}/MWh_{el}$ [22]
  - Heat factor based on the actual German heat mix; heat GWF of 0.216 Mg $CO_{2,äq}/MWh_{th}$ [32]

The actual German power mix consists of a wide range of energy sources, so as to not to be dependent on one source. The future aim is to reduce the nuclear power fraction and replace it by renewable energy. As was shown in Fig. 5, natural gas is the "cleanest" fossil energy with the highest conversion efficiencies. Clean is not only meant in terms of low emission of carbon dioxide; during combustion of natural gas, other emissions such as sulfur oxides, hydrochloric acid, carbon monoxide, and particulates are much lower than from other fossil fuels. For this reason, Germany is making further efforts to increase the use of natural gas by expanding gas pipeline connections to Russia.

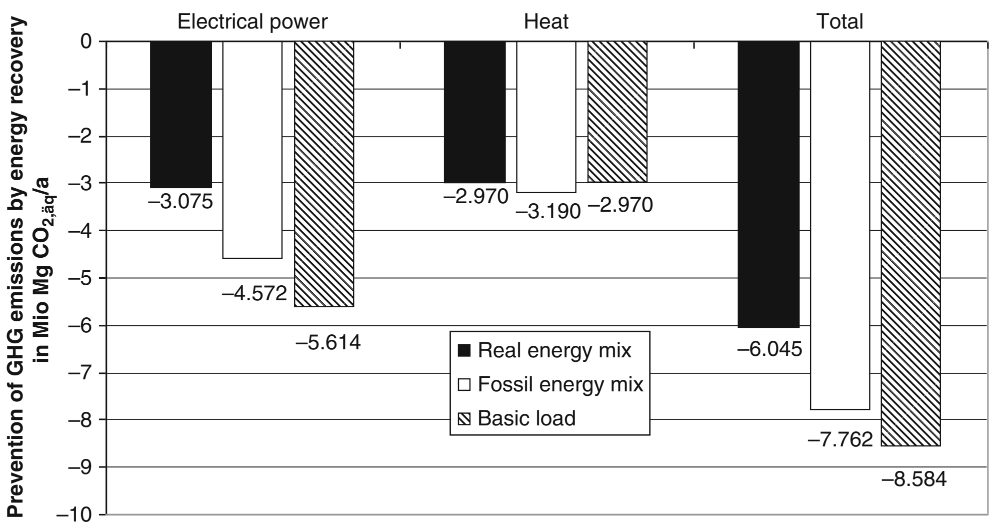
As noted earlier, data on industrial heat is hard to obtain; therefore, the above distribution of heat for the actual German energy scenario is based on the provision of district heat. The majority of provided heat is produced by hard coal and natural gas fired power plants, in combined heat and power generation. Actually, nearly 90% of the district heating in Germany is produced in cogeneration with electricity [32]. This cogeneration is financially supported by the German government by implementing high-efficiency technologies and in order to reduce GHG emissions.

The fossil power mix for Germany consists of hard coal and to a lesser degree by lignite and natural gas. The fossil heat mix is based on the energy source share of the German heat market in 2003 [32].

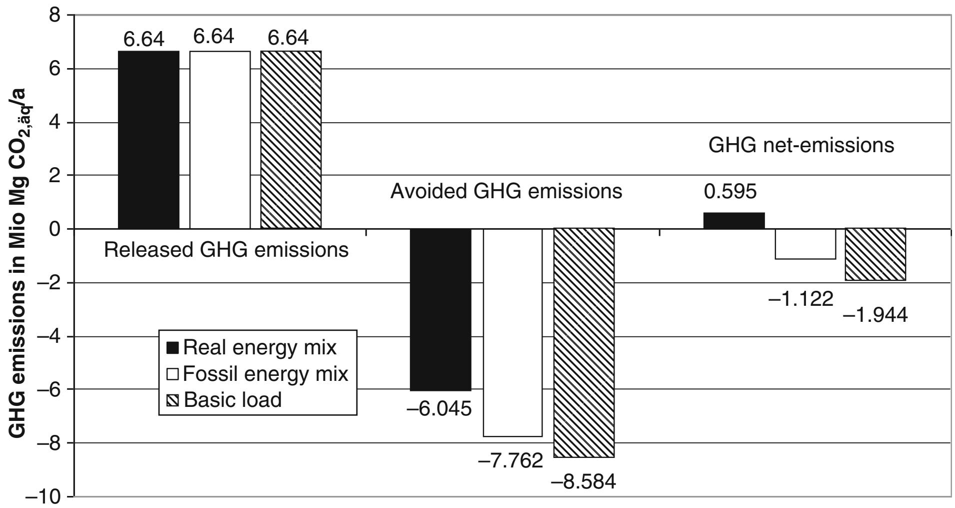
Apart from nuclear power, the base load of electricity in Germany is provided by lignite. Nuclear power has little effect on GHG, so the base load scenario involves substitution of lignite by MSW incineration. For the base load of heat, the actual heat mix factor was used, because the heat requirements change with season rather than time of the day.

Multiplying the amounts of electricity and heat provided by WTE (see Table 8) by the substitution factors of the three scenarios yields the amounts of GHG emissions avoided by substituting MSW incineration for the combustion of fossil fuels (Fig. 12).

The avoided GHG emissions are shown as negative numbers in Fig. 12. The three bars on the left side of Fig. 12 show the effect of WTE in substituting fossil fuels for electricity generation. Substitution of heat



Greenhouse Gas Emission Reduction by Waste-to-Energy. Figure 12
Avoided GHG Emissions in Germany by means of energy recovery in waste incineration plants in 2007, under three energy mix scenarios



Greenhouse Gas Emission Reduction by Waste-to-Energy. Figure 13
GHG emissions, avoidance of emissions, and net emissions of German waste incineration plants in 2007

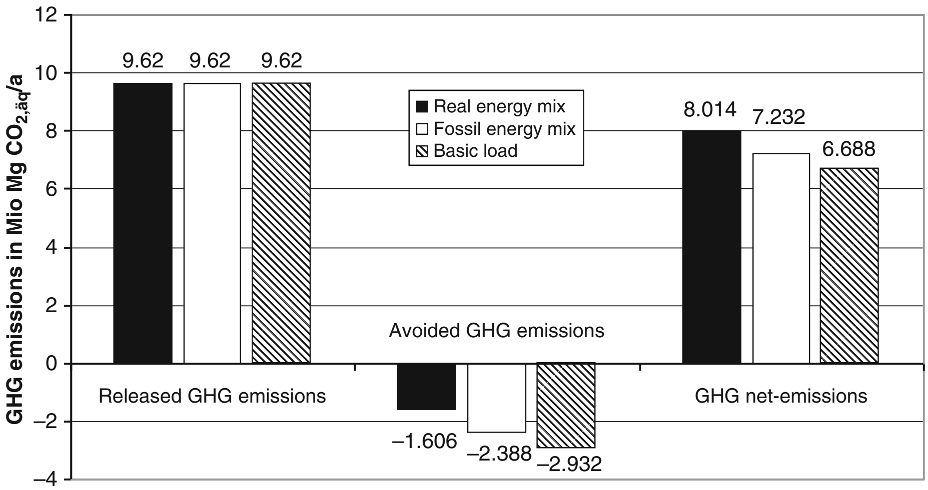
energy (three bars in the middle) results in lower avoidance of GHG emissions because heat generation in Germany is very efficient, and the substitution factors lower. The avoided GHG emissions range from 3 and 5.6 million Mg $CO_{2,äq}$/a. In total, the GHG emissions avoided by WTE electrical and thermal energy range from 6 to 8.6 Mio Mg $CO_{2,äq}$ per year. By adding the WTE GHG emissions and the avoided (i.e., negative) emissions of fossil fuels avoided because of the energy generated by WYE (Fig. 12) results in the net GHG emissions shown in Fig. 13 (last three bars).

The German example shows that the scenario chosen for substitution of energy is very important and has a real impact on the GHG balance of WTE plants. In the case of substitution in the actual German energy mix, the GHG net emissions (0.6 million Mg $CO_{2,äq}$/year) is positive. For the substitution of the fossil energy mix and the base load scenarios, the GHG balance is negative, and GHG emissions of 1.1 and 2 million Mg $CO_{2,äq}$/year are avoided.

Comparison to Landfilling

Currently, 95% of all German landfills are equipped with a gas collection system, and the biogas collection efficiency has been estimated at 60% [33]. If it is assumed that the 17.8 million Mg of incinerated MSW were landfilled and using the calculations presented in the section "Greenhouse Gas Emissions by Landfilling", 9.6 million Mg $CO_{2,äq}$ would be directly released. The gas collection systems would capture about 0.4 million Mg of methane. Since the LHV of methane is 13.9 MWh/Mg, the captured gas would provide about 5.6 million MWh that could be used to generate energy in the form of electricity and heat. Usually the landfill gas is burned in slightly modified gasoline engines to produce electricity only. Heat is generally not needed at landfills, and therefore not recovered. The electrical efficiency of the gasoline engines is around 35%. Assumed that all of the captured landfill gas can be used in gasoline engines, about 2 million MWh of electricity would be produced. This electricity would substitute energy produced by other fossil fuels, and thus avoid GHG emissions. On the basis of the substitution scenarios for Germany (see Section Prevention of Greenhouse Gas Emissions by Energy Recovery in German Waste Incineration Plants) between 1.6 and 3 million Mg $CO_{2,äq}$ of fossil fuel emissions would be avoided. Figure 14 shows what would be the effect of landfilling, instead of combusting, 17.8 million Mg on the GHG emissions balance for Germany, for the same three energy mix scenarios.

Figure 14 shows that even if all of the captured methane were used to generate electricity, the GHG



Greenhouse Gas Emission Reduction by Waste-to-Energy. Figure 14
GHG emissions in Germany if 17.8 million tons of MSW were landfilled rather than combusted in 2007

net emissions would be between 6.7 and 8 million Mg $CO_{2,äq}$. In comparison to waste incineration (see Fig. 13), the GHG net emissions by land filling would be about 8 million Mg $CO_{2,äq}$, higher than in the case of waste incineration with energy recovery. This amount corresponds to about 0.5 t of carbon dioxide per ton of MSW landfilled rather than combusted. The landfill emissions would be much greater for landfills that do not recover methane or flare the landfill gas instead of using it to generate electricity.

Future Directions

This entry shows clearly that waste incineration results in much lower GHG emissions than landfilling. One of the reasons is that only CO_2 is emitted during incineration, while the landfill gas that is not captured consists of about 50% methane that has a global warming potential that is 23 times higher than the same volume of carbon dioxide. The second reason is that much more energy is generated by the combustion of MSW than from the combustion of the methane generated and captured during landfilling.

Many communities have begun to collect biodegradable materials separately. The result is less biogenic fixed carbon in the household wastes and a higher amount of plastics and composite materials with high amounts of fossil-fixed carbon. The result are a lower amount of landfill gas generated during landfilling and a corresponding reduction in GHG emissions. For the waste incineration, removal of organics results in a higher concentration of fossil-based wastes and higher GHG emissions. It also means higher calorific value of the MSW which should result in higher thermal efficiency. In any case, it is necessary for WTE plants to strive to increase their thermal efficiency and energy recovery. This will result in higher amounts of produced and delivered energy and, thus, higher substitution of fossil fuels and increased avoidance of GHG emissions.

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